

DRAFT

OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY AIR QUALITY DIVISION

MEMORANDUM

March 18, 2011

TO: Phillip Fielder, Permits and Engr. Group Mgr.

THROUGH: Kendal Stegmann, Sr. Environmental Manager, Compliance and Enforcement

THROUGH: Phil Martin, P.E., Engineering Section

THROUGH: Peer Review, David Pollard, DEQ Regional Office at Tulsa (ROAT)

FROM: Herb Neumann, DEQ ROAT

SUBJECT: Evaluation of Permit Application No. **98-171-C (M-2) PSD**
NORIT Americas, Inc.
Pryor Activated Carbon Plant (SIC 2819)
SW/4 SE/4 Sec. 4, T20N, R19E, Mayes County (36.238° N, 95.286° W)

Driving: From intersection of US 412 and US 69, six miles north to US 69A, three miles east to US 412B (Hunt Street), one mile south to 6th Street, almost ½ mile west, plant on left. Alternately, from US 412 and US 69, three miles east to US 412B (becomes Hunt), almost five miles north to 6th Street, same as above.

SECTION I. INTRODUCTION

NORIT Americas owns and operates a virgin activated carbon or VAC (original straight run and acid washed carbon) manufacturing plant and a spent activated carbon (SAC) regeneration facility at its Pryor, Oklahoma facility. The facility was originally constructed in 1979 as authorized by Permit No. 78-002-C. A table listing each permit and its issue date is available in the Memorandum associated with Part 70 operating permit No. 98-171-TV, issued October 11, 2010. Numerous additions and changes in operation of the facility have been authorized over the years. At issue in this application is the construction of the primary carbonizer and ancillary equipment authorized by Permit No. 88-105-C. Information supplied in the application indicated that no pollutant would have emissions of more than 250 TPY on a facility-wide basis after completion of the project. Although EPA has determined that the major stationary source threshold for this type of facility is 100 TPY, DEQ believed (in 1988) that the threshold was 250 TPY, so that the facility did not require Prevention of Significant Deterioration (PSD) analysis. A subsequent material balance performed by the facility indicated that the primary carbonizer project exceeded the 250 TPY threshold by itself and should have been subject to PSD analysis, regardless of the actual threshold. Further, any such analysis should have included all potential upstream and downstream effects of the project. A Consent Order (CO) dated August 6, 2007, requires that a retroactive PSD analysis be performed for the project. The analysis shall cover the primary and secondary carbonizers and both activators. The current application contains the

required analysis and discusses the construction of various control equipment, as described in the following paragraph.

Consent Order 07-010, issued August 6, 2007, required that a revised Title V application be provided and that a retroactive PSD analysis be prepared for the primary carbonizer project. The revised Title V application was received December 4, 2007 and the operating permit has been issued, as stated in the Introduction. An application covering the PSD analysis was received on the same date, and is the subject of this permit. The Order also required that additional control be added to the activation furnaces, which has been accomplished by adding cyclones following each activation furnace and before the afterburner for each. Finally, the Order required the installation of additional PM control on the secondary carbonizer. This was accomplished by adding a bank of mini-cyclones in the exhaust stream after the afterburner and waste heat boiler.

Modeling for the new 1-hour SO₂ NAAQS standard indicated exceedances at several points. These exceedances could be removed only by adding control equipment or by rerouting certain emissions. The facility has performed necessary modeling for these scenarios, but has not selected a method of compliance. Equipment and emission points shown in this Memorandum and authorized in the permit are unchanged from those in the existing Part 70 operating permit. A compliance plan setting a schedule for selection and implementation is contained in the Specific Conditions.

SECTION II FACILITY DESCRIPTION

Process descriptions for the base operating scenarios for the VAC and SAC plants follow. No alternative operating scenarios are required to define operations at the facility. Commercial-grade natural gas is the primary fuel, with the facility being operated continuously. The following descriptions appear in the Memorandum for 98-171-TV, but the only portion of concern in this permit effort is Area 30.

Virgin Plant Operation

- Receiving bituminous coal, subbituminous coal, and coal tar pitch by truck and rail from various sources; unloading and storing the coal and pitch.
- Drying the coal, blending with coal tar pitch, milling and compacting the coal/pitch material into uniform briquettes, and grinding the briquettes to the desired granule size.
- Processing the granulated briquettes through carbonizers (kilns), using natural gas as the primary fuel source for carbonization, to drive off the volatile matter and produce carbonized granules. Using heat from natural gas combustion in multiple hearth furnaces (activators) together with steam to activate the carbon; that is, to create a porous structure in the carbon.
- Additional milling to create powdered products. Handling, storing and loading of the activated carbon into bags or trucks for final shipment to customers.
- Using dilute hydrochloric acid (HCl) to remove, through a wash or leach operation, acid-soluble constituents from part of the activated carbon produced by the virgin plant.

The virgin plant utilizes the following five basic operating areas.

- Area 10 - Material Handling Operations
- Area 20 - Material Drying, Milling, Compacting and Sizing Operations
- Area 30 - Carbonizing and Activation Operations
- Area 40 - Finished Product Packaging Operations
- Acid Wash Plant Operations

Area 10 - Material Handling Operations

Coal arrives at the plant via rail or truck and is unloaded in the raw material unloading building or at the coal unloading pile, and is moved within the unloading building, eventually to the working coal storage pile. Front-end loaders are used to transfer the coal into either the open coal storage area or into the dry coal storage building, as well as to maintain the coal piles in both areas. They also transfer coal from the piles to the coal hoppers at the beginning of Area 20 operations. The only particulate matter (PM) emission controls for the storage buildings and chutes are enclosures, some partial and others complete.

Coal is “reclaimed” from the coal storage and processing areas by a front-end loader that transports the reclaimed coal and maintains the reclaim coal pile. Front-end loaders transfer the coal to the reclaim coal hopper and transfer reclaimed coal to Area 20 operations.

Coal tar pitch, which is used in Area 20 as a coal binding agent, arrives at the plant via rail or bulk bags. The pitch received by rail is unloaded in the raw material unloading building, where it is transferred into piles within the pitch storage building. During rail offloading, negative pressure is maintained in the pitch storage building and any emissions are captured, reduced by the pitch storage building high efficiency panel filter, and vented through the pitch building exhaust stack. The pitch storage building is normally closed, except during periods of pitch maintenance/reclaim by front-end loader and while dropping pitch into the pitch hopper. Bulk bags are normally received in iso containers and are stored in the pitch building, in the SAC warehouse, or emptied onto the pitch building storage pile. Pitch is transferred to Area 20 via a front end loader and dumped into the pitch receiving hopper. The pitch hopper is enclosed, maintained under negative pressure, and controlled by the Area 20 dust collector.

Area 20 - Material Sizing and Drying Operations

The purpose of Area 20 is to form the raw coal and pitch materials into a homogeneous material of uniform size and hardness, as required for activated carbon processing in Area 30. Phosphoric acid is added to incoming subbituminous coal as a processing aid. The process chemistry is such that there are no phosphoric acid emissions from this process. A purged air and steam coal dryer removes moisture from the coal. After the coal is dried, it is then pulverized and ground with the pitch and compacted into granular briquettes of uniform hardness. The briquettes are milled to the desired granule size. The granular material is dropped into a surge bin to control the transfer rate to Area 30 operations. The coal drying operation, Area 20, is subject to NSPS Subpart Y – Coal Preparation Plants. The coal dryer dust collector controls PM emissions from the coal

dryer. The Area 20 dust collector controls PM emissions from other coal handling operations in Area 20.

Area 30 - Carbonizing and Activation Operations

The primary processes within Area 30 are two external natural gas fired kilns, designated as the primary and secondary carbonizers, and the activators. The primary and secondary carbonizers are slowly rotating cylindrical furnaces in which the granular material to be processed is continuously agitated by “flights” as it moves forward in the kiln. Heat is supplied indirectly by gas-fired burners (heating jackets) that heat the outside of the rotation tube. Heat is transferred to the granular material by conduction and radiation. A counter-current flow of heated air is used to purge the tubes of the volatilized products and coal fines and to begin the reaction process to formulate the pore structure. The carbonizers drive off water and organic compounds and reduce the carbon/pitch feed material to elemental carbon. Thus, the material is said to be “carbonized.”

The granules produced in Area 20 are fed to the primary carbonizer. The primary carbonizer feed bag house controls emissions from the raw material feed system. The primary carbonizer operates at a lower temperature range and is the initial step in drawing off the volatile matter. This process continues at higher temperatures in the secondary carbonizer. Heated air with reduced oxygen is used in the secondary carbonizer to reduce oxidation of the carbon. The process off-gases contain particulate matter and volatile matter. Organic compounds are controlled by thermal oxidation in afterburners for both carbonizers. Waste heat boilers follow each afterburner. The secondary carbonizer has a multiclone particulate separator for PM control after the exhaust stream exits the waste heat boiler.

The carbonized granules are then fed to the east and west activators for further processing. These are two multiple hearth activation furnaces that operate in parallel. Each activation furnace consists of a refractory-lined cylindrical steel shield containing a series of horizontal refractory hearths. These hearths have alternate in-feed and out-feed directions, causing carbon granules to move completely across each hearth as they drop from one level to another. The hearths have the effect of creating a counter-current flow of carbon granules and hot process gases. Mechanical stoking is provided by a motor-driven revolving center shaft to which radial arms are attached. These arms have teeth (or plows) attached that move the material across the hearth to the peripheral or central openings, called drop holes, through which the granules drop to the next hearth. Multiple gas-fired burners provide auxiliary heat. Steam and process air is introduced selectively at various hearths from levels 2 through 12 to control and enhance the activation process. The upper hearths are used to heat the carbon and drive off any remaining volatile compounds. The remaining hearths are used for the actual activation of carbon. The process off-gases contain products of natural gas combustion, particulate matter, and some remaining volatile compounds. The offgas from each activation furnace passes through a cyclone for the removal of particulate matter. PM recovered by these units is generally salable material and is returned to the activation furnace. Offgas leaving each cyclone then enters an afterburner for each unit to oxidize any remaining organic matter. Exhaust gases from the afterburners may be emitted to the atmosphere directly or passed through a waste heat boiler first.

Area 40 - Finished Product Packaging Operations

Activated carbon from Area 30 is then screened, packaged, and/or milled into powdered activated carbon (PAC) as necessary in Area 40. Porous activated carbon granules are

transferred from the activation furnaces and dropped into the Area 40 product screener. Emissions are controlled by the Area 40 Auxiliary Dust Collector. Depending on customer requirements, the activated carbon granules and fines can be sent to the powdered activated carbon (PAC) mill for milling or to the packaging area. The PAC mill dust collector controls PAC mill emissions and the Area 40 dust collector controls packaging emission.

Acid Wash Plant Operations

The acid wash plant (AWP) is an auxiliary process to the virgin activated carbon manufacturing plant. The AWP uses dilute hydrochloric acid (HCl) to remove, through a wash or leach operation, acid soluble constituents from activated carbon produced by the virgin plant. This auxiliary process allows the production of a higher quality activated carbon that is required by certain industrial processes, such as food processing or pharmaceuticals.

The activated carbon granules from the activation furnaces are transferred from Area 40 and dropped into the acid wash reactor in batches. The activated carbon is processed through a relatively high temperature, medium pressure reaction with dilute HCl. The batch is then water washed in several steps. A buffering/neutralizing agent may be used as a rinsing agent to adjust the quality of the plant water supply. Following the water washing, the batch is then de-watered. A natural gas-fired acid-wash dryer is used to reduce the moisture content. The final product is sized and packaged.

Emissions from the HCl storage tank pass through a caustic scrubber. PM emissions arising from the transfer of granules to the acid wash reactor are controlled by the Area 20 dust collector. PM emissions from the acid wash dryer, product screener and product bin are controlled by the AWP dust collector and vented through its stack.

Regeneration Plant Operation

Spent activated carbon (used activated carbon that has adsorbed chemical constituents) is typically brought to the regeneration plant via bulk tank trucks and containers. Bulk tank trucks are pressurized to drive the spent activated carbon (SAC) into storage silos, where it is conveyed into a feed silo, and then into the regeneration kiln. Alternatively, bulk trucks are offloaded onto the SAC storage pad, which is a contained, outdoor unit. SAC received in containers is received and stored/staged in a warehouse or stored outside. Bulk SAC is transferred from the SAC pad to the Regen kiln feed hopper (F hopper). Containerized SAC is transferred from the warehouse and manually poured into the F hopper or poured onto the SAC pad. The regeneration kiln drives the adsorbed chemical constituents from the spent carbon. After regeneration, the reactivated carbon is cooled in a non-contact water-cooled heat exchanger, then screened and packaged or bulk loaded into trucks.

Emission controls in the regeneration process include an afterburner, a baghouse, and an alkaline scrubber (for HCl and SO_x removal). When the afterburner is not in service, the silos vent any VOC emissions through a carbon canister. The Regeneration Product Area Dust Collector controls packaging emissions. Truck loading operations use only a chute to control emissions.

SECTION III. EQUIPMENT

Emission units (EUs) have been arranged into Emission Unit Groups (EUGs) in Section III (Equipment), based on activity, type of control, and permitting status. All EUGs are listed, but only those in Area 30 are described.

EUG 1 Facility-wide**EUG 2 Primary Carbonizer/Afterburner**

| EU | Point ID | Name/Model | Const. Date |
|----|-----------|---|-------------|
| 17 | SV-VP-005 | Primary Carbonizer/ Afterburner/Waste Heat Boiler | 1990 |

The PC afterburner has three burners with 12 MMBTUH total heat input.

EUG 3 Secondary Carbonizer/Afterburner

| EU | Point ID | Name/Model | Const. Date |
|----|--------------|--|-------------|
| 12 | SV-VP-007a,b | Sec. Carb./Multiclone/Afterburn/ Waste Heat Boiler | 1979* |

*Multiclones were installed and became operational 10/9/2006.

Oxygen content of sweep air supplied to the SC is depleted by a 14.6 MMBTUH burner. The SC afterburner has two burners with 1.9 MMBTUH total heat input. The (a) stack is designated for the direct discharge of the afterburner and the (b) stack is designated for the discharge of the waste heat boiler. The afterburner also has supplemental gas feed used as necessary. Combined maximum potential heat input is estimated at 18 MMBTUH.

EUG 4 Primary Carbonizer Heating Jacket

| EU | Point ID | Name/Model | Const. Date |
|----|-----------|-----------------------------------|-------------|
| 21 | SV-VP-006 | Primary Carbonizer Heating Jacket | 1990 |

The primary carbonizer (PC) heating jacket has eight burners with total heat input of 8 MMBTUH.

EUG 5 Secondary Carbonizer Heating Jacket

| EU | Point ID | Name/Model | Const. Date |
|----|-----------|-------------------------------------|-------------|
| 22 | SV VP 008 | Secondary Carbonizer heating jacket | 1979 |

The secondary carbonizer (SC) heating jacket has 8 burners with 10MMBTUH total heat input.

EUG 6 Multiple Hearth Activation Furnaces

East and west activation furnaces each have 20 small burners with total heat input of 25 MMBTUH and each has a single 2.2 MMBTUH burner in its respective afterburner.

| EU | Point ID | Name/Model | Const. Date |
|----|---------------|---------------------------|-------------|
| 10 | SV-VP-009a, b | Activation Furnace – East | 1979 |
| 11 | SV-VP-010a, b | Activation Furnace – West | 1979 |

Exhausts from each hearth flow through a cyclone for PM removal/recovery and to an afterburner for destruction of organic material. A portion of both gas streams vent through a common waste heat boiler (a) or are discharged directly to the atmosphere (b).

EUG 7 Acid Wash Dryer

EUG 8 Material Handling & Transfer – Controlled

EUG 9 Coal Processing Plant (Area 20)

EUG 10 Material Handling, Transfer, Traffic, & Erosion – Uncontrolled

EUG 11 Acid Wash Plant Material Handling & Transfer – Controlled

EUG 12 Material Handling & Transfer – Controlled

EUG 13 Material Handling, Transfer, Traffic, & Erosion – Uncontrolled

EUG 14 Truck Unloading

EUG 15 Regeneration Kiln/Afterburner

EUG 16 Regeneration Plant Material Handling

EUG17 Regeneration Plant Bulk Handling

EUG18 Hydrochloric Acid Storage Tank

EUG 19 NSPS Subpart Dc Boiler (Permit No. 98-171-C (M-1))

EUG 20 Cooling Tower

SECTION III. EMISSIONS

Calculating emissions from the carbonizers and activators is difficult. Analyses from previous permit memoranda, including the current Part 70 permit, are set aside, and only the methods proposed in the application are used. As a consequence of the consent order, PSD analysis was required and submitted. This analysis used estimated emissions from each affected unit, using a material balance calculation. PM emissions from the VAC can be assessed by considering the amount of dry material feed and the amount of dry material product. This can be refined by reviewing the amount of dry feed at each of the processing units; that is, at the primary carbonizer, the secondary carbonizer, and at the activator hearths, allowing a calculation of what portion of total emissions is attributable to each process component. Further considerations address ash content of the raw material and review both the genesis and the fate of both ash and non-ash PM. For the purposes of modeling, cyclones are assumed to be 80% efficient and

afterburners 90% efficient, noting that afterburners affect only the non-ash PM. This methodology involves confidential data, so no further discussion is offered here, but the method is addressed in the Specific Conditions of Permit No. 98-171-TV. The following table shows both sets of potential limits. For the purpose of reporting PM emissions using the model described above, all values of PM are assumed to be PM₁₀. Annual values are based on 8,760 hours of operation. The activators are listed individually, but share a common exhaust header. The Part 70 permit memorandum lists East and West activator stacks on the assumption that each shares equally in the processing. Because of the manner in which emissions will ultimately exhaust and differing stack dynamics, this analysis asserts a roughly 75/25 split as an engineering estimate, depending on whether or not any bypass is occurring. The post-project total is 602 TPY of PM₁₀ emissions. NORIT conducted particulate matter stack tests on major stacks at the Pryor Facility in May 2009. The stack tests contained 11 cumulative particle size analysis profiles for two emission sources. The cumulative PM_{2.5} volume percent ranged from 0.82% to 14.02% of all PM₁₀. The weight percent numerically equal to the highest volume percent measured during the tests (14.02%) is used to represent the ratio of PM_{2.5} to PM₁₀ as a conservative estimate.

| Unit | PM ₁₀ | |
|----------------------|------------------------------|--------|
| | Material balance calculation | |
| | Lb/hr | TPY |
| Primary carbonizer | 46.5 | 203.51 |
| Secondary carbonizer | 30.74 | 134.66 |
| Existing stack | 15.07 | 66.01 |
| Proposed stack | 45.21 | 198.03 |

Post-project emissions of NO_x are calculated based upon 2004 stack testing results. There is no reason to assume linearity; that is, emissions of this pollutant will probably not increase linearly with increased production, because thermodynamic considerations are not predictable. The facility's consultant suggested that the emissions be treated as varying directly with the square of the production rate. Because these calculations reveal proprietary process information, only the results (782.71 TPY) are given.

Post-project emissions of CO are calculated in the same manner as those of NO_x, yielding 20.91 TPY.

Emissions of VOC from the carbonizers and MHFs may exist, but residence time in the afterburners is sufficient that only very small amounts will be released to atmosphere. No limits have been set for VOC emissions from these units, and little to no change in emissions is assumed to have occurred. .

Total emissions of SO₂ from the VAC are estimated based on material balance for the entire process. The sulfur content of the raw material (feed) is known or measurable, as is the sulfur content of the product. The amounts of feed and of resulting product are also known factors. The loss in sulfur between inlet and outlet may be calculated from these known data, and by assuming that all of this sulfur is stoichiometrically oxidized to sulfur dioxide, we arrive at emissions of SO₂.

Although some stack tests showing the amount of SO₂ from each of the potential sources have been performed, varying thermodynamic conditions and minor changes in the physical attributes of the feed make it impossible to predict the proportion of SO₂ emissions attributable to each stack. Modeling parameters used for this retroactive PSD application suggest a division of 7.9% at the primary carbonizer, 23.6% at the secondary carbonizer, 34.0% at the activator boiler, and 34.5% at the new activator stack. Total post-project emissions allocated to these emission points, assuming continuous operation at maximum throughput and high sulfur content, is 1,658 TPY of SO₂.

Emissions of inorganic pollutants chlorine and hydrogen chloride were calculated using 2004 METCO test data and scaling linearly to maximum throughput capacity. This yielded emission totals of 9.22 TPY of chlorine and 21.73 TPY of hydrogen chloride. Other sources and amounts of hydrogen chloride emissions follow.

HCl Emissions

| Emission Unit | Lb/hr | TPY |
|-------------------------|-------------|--------------|
| Acid Wash Plant Dryer | 4.09 | 9.29 |
| Hydrogen Chloride Tanks | 0.53 | 1.37 |
| Regeneration Plant | 4.08 | 17.87 |
| Totals | 8.70 | 28.53 |

SECTION IV. INSIGNIFICANT ACTIVITIES

None of the insignificant activities identified in the Part 70 permit application is affected by this project, so the list is not duplicated here. It is available in the Memorandum associated with Permit No. 98-171-TV.

SECTION V. PREVENTION OF SIGNIFICANT DETERIORATION (PSD)

Calculation of post-project emissions was discussed in Section III above. Note that the calculations of emissions were based on a VAC-wide analysis, because of the difficulty of identifying the exact point(s) at which losses occur. Because the operation of the activators or multi-hearth furnaces (MHFs) is essentially unchanged by the project, comparison of VAC-wide emissions pre-project and post-project provides a good demonstration of the effect of the project, especially for purposes of determining PSD applicability. Pre-project emissions were reported based on the following criteria.

- PM emissions are taken from 1986 and 1986 actual data.
- SO₂ emissions are taken from 1986 and 1987 actual data.
- NO_x emissions from 1986 and 1987 are unknown or unavailable. Emissions are taken from 2004 and 2005, which are considered to be representative years.
- CO emissions are unavailable and a value of zero is assumed for prior actual purposes.

The table of pre-project “actual” emissions follows.

| Pollutant | Emission Type | Emissions in TPY | | | | PSD Threshold | Significant? |
|-----------------|---------------|------------------|--------|-------|--------|---------------|--------------|
| | | PC | SC | MHF's | Total | | |
| PM | Past | 0 | 984 | | 984.0 | | |
| | Post | 203.5 | 134.7 | 264.0 | 602.2 | | |
| | Change | 203.5 | -849.3 | 264.0 | -381.8 | 25 | N |
| SO ₂ | Past | | | | 370.3 | | |
| | Post | | | | 1658 | | |
| | Change | | | | 1287.7 | 40 | Y |
| NO _x | Past | 0 | 22.5 | 150.1 | 172.6 | | |
| | Post | 49.3 | 184.0 | 549.5 | 782.7 | | |
| | Change | 49.3 | 161.5 | 399.4 | 610.1 | 40 | Y |
| CO | Past | 0 | 0 | 0 | 0 | | |
| | Post | 0.37 | 1.23 | 10.78 | 12.38 | | |
| | Change | 0.37 | 1.23 | 10.78 | 12.38 | 100 | N |

There were no applicable contemporaneous increases or decreases, so conclusions as to significance shown in the table remain unchanged; SO₂ and NO_x require further analysis.

A BACT Review is required for new and modified emission units that result in a PSD net emission increase. Title 40 CFR 52.21(j)(3) codifies the BACT requirement as follows: “A major modification shall apply best available control technology for each pollutant subject to regulation under the Act for which it would result in a significant net emissions increase at the source. This requirement applies to each proposed emissions unit at which a net emissions increase in the pollutant would occur as a result of a physical change or a change in the method of operation.”

The scope of the 1988 project at the Pryor Facility was the installation of a new carbonizer, called the primary carbonizer because it was installed upstream of the existing (now secondary) carbonizer. The purpose of the project was to increase VAC production capacity and allow the use of varying types of coal as VAC process feedstock. The historical project descriptions indicated that the physical changes associated with the project included the addition of the primary carbonizer and associated material handling systems. As previously presented in Section 2, the feed from the primary carbonizer was subsequently directed to the secondary carbonizer. Therefore, the feed conveyance system to the secondary carbonizer may be considered to have been modified as a result of this 1988 project, arguably resulting in a modification to the secondary carbonizer. The project description contained no discussion of other physical changes made to equipment within the VAC process. Additionally, it is not believed that there was a change in the method of operation for any downstream process after the secondary carbonizer (i.e., the MHFs). This is due to the fact that EPA does not consider a change in feedstock a change in the method of operation if the emission unit was always capable of processing the feedstock. It is apparent that the MHFs could always have processed the “new” feedstock to the extent that it was properly carbonized since there were no physical changes made to the MHFs.

In November 2006, NORIT added a new waste heat boiler (WHB) downstream of the Secondary Carbonizer afterburners to produce steam for use at the plant. No direct or indirect emissions

increases associated with the addition of this WHB were expected due to the fact that this equipment does not combust fuel and no debottlenecking occurred as a result of the addition of this equipment. The WHB generates steam through the transfer of heat from the hot exhaust stream from the Secondary Carbonizer to water flowing through a noncontact heat exchanger.

There are at least two EPA policy and guidance memorandums that address the applicability of BACT to downstream emission units. One is the 1989 Detroit Edison policy memorandum where EPA states that “The BACT requirement applies to each ‘proposed emissions unit at which a net emission increase would occur as a result of a physical change or a change in the method of operation of the unit [see 52.21(j)(3)].’ ” The policy memorandum reviews the PSD and BACT applicability to a project to burn an alternate fuel, natural gas, in a boiler at the Detroit Edison facility. The PSD determination found that even though the boiler could not accommodate combustion of natural gas prior to January 6, 1975 and required new burner canes, burning an alternate fuel did not constitute a physical change or change in method of operation that required a BACT review. This determination was based on the presumption that only the addition of burner canes would be required to burn natural gas and EPA’s historical position that “...where the individual boiler being converted is capable of accommodating the alternate fuel, BACT would not apply.”

A July 28, 1983 memorandum also discussed the BACT requirement and its applicability to upstream and downstream units. The 1983 memorandum describes a process in which a pulp and paper mill installs a new bleaching plant and a larger digester. The installation of these two facilities did not itself result in an emissions increase. However, emissions at the recovery boiler downstream of the new and modified units increased. As stated in the memorandum, “Since the recovery boiler itself will not be undergoing a physical change or in the method of operation, it will not have to apply BACT.”

Given the discussions above, the scope of the BACT analysis herein covers the primary and secondary carbonizers. The MHFs are not subject to BACT review because they did not experience a physical change or change in the method of operation as a result of the addition of the primary carbonizer. The primary carbonizer was installed to serve two important process functions: feed pre-treatment and commencing the initial oxidation and carbonization processes. The addition of the primary carbonizer allowed NORIT to achieve a higher overall process yield and process a wider variety of coal. Even if the ability to process a wider variety of coal is believed to be a modification, EPA’s historical stance has been that if the emission unit being converted is capable of accommodating the alternate material without significant physical modifications, then BACT does not apply. Since the modification would add emissions above PSD levels of significance, the application has been determined to require full PSD review. Full PSD review consists of the following.

- A. Determination of Best Available Control Technology (BACT).
- B. Evaluation of existing air quality and determination of monitoring requirements.
- C. Analysis of compliance with National Ambient Air Quality Standards (NAAQS).
- D. Evaluation of PSD increment consumption.
- E. Evaluation of source-related impacts on growth, soils, vegetation, and visibility.
- F. Evaluation of Class I area impacts.

Step A analysis for NO_x will be reviewed first, followed by Step A for SO₂, then followed by Steps B through F for all pollutants.

A. BACT for NO_x

Step 1 – Identification of all available control options

In order to identify available control technologies, a search of US EPA's RACT/BACT/LAER Clearinghouse (RBLC) was conducted to identify recent permitting actions and recent BACT determinations.

First, RBLC is searched for BACT determinations for the same emission unit and same process, then, for similar emission units and similar processes. As a final step, additional permitting files are reviewed to identify determinations that are not recorded in the database.

The clearinghouse was first searched for the terms: carbonizer; activated carbon; activation; activation furnace; and carbon.

Only the search for "activation furnace" returned any results. However, these results were for munitions and explosives "deactivation furnaces" which is not a similar process or emission unit to those at NORIT Pryor Facility.

Next, four "similar" processes were identified for the purposes of this BACT review: carbon black manufacture, calcined coke manufacture, petroleum (needle) coke manufacture, and clay brick manufacture.

Carbon Black Industry

The carbon black industry is similar to the VAC production process in that a carbonaceous feedstock is heat-treated to create a saleable product (carbon black) that exhibits certain desired chemical properties. In the carbon black process, heavy oil is thermally reacted, resulting in significant quantities of waste gas or tail gas. The principal source of emissions in the oil furnace process is the main process vent. The vent stream consists of the reactor effluent and the quench water vapor vented from the carbon black recovery system. Gaseous emissions may vary considerably according to the grade of carbon black being produced. NO_x emissions in the main process vent gas may result from the combustion of the natural gas fuel for the dryer and other processes. Gaseous emissions from the main process vent other than NO_x may be controlled with CO boilers, incinerators, or flares. The pellet dryer combustion furnace, which is essentially a thermal incinerator, may also be employed in a control system. CO boilers, thermal incinerators, or combinations of these devices can achieve essentially complete oxidation of organics and can oxidize sulfur compounds in the process flue gas but result in increases of NO_x emissions for these sources. NO_x emission levels from the carbon black process are similar to those seen in the VAC production process and add-on NO_x emission controls have not been required by regulatory agencies for these sources. This analysis suggests that additional add-on control may not be required as BACT for NO_x emissions from the VAC production process.

Calcined Coke Industry

The calcined coke industry is also similar to the VAC process in that a carbonaceous feedstock is processed in calciners at high temperature to drive off excess moisture and to create a dried product (calcined coke) that exhibits desired chemical properties. In the calcined coke process, petroleum coke from refinery coker units is used as the feedstock. Similar to VAC processes, some refinery coke used as feedstock is also combusted as part of the fuel source, in turn generating NO_x emissions. The resulting tail gases from this process, therefore, contain

significant quantities of NO_x emissions that are orders of magnitude higher than those seen in the VAC production process. US EPA has not required add-on NO_x control for these sources, and add-on NO_x controls are not used in this industry. This analysis suggests that additional add-on control may not be required as BACT for NO_x emissions from the VAC production process.

Petroleum Coke Industry

The petroleum coke industry is also similar to the VAC process in that a carbonaceous feedstock is processed in kilns at high temperature to drive off excess moisture and to create a dried product (needle coke) that exhibits desired chemical properties. In needle coke manufacturing, petroleum coke from refinery coker units is used as the feedstock. The petroleum coke process typically generates significant quantities of nitrogen dioxide from the combustion of the coke in the kilns. The resulting tail gases from this process contain significant quantities of NO_x emissions that are orders of magnitude higher than those seen in the VAC production process. Similarly to other coke production industries discussed above, US EPA has not required add-on NO_x control for these sources, and add-on NO_x controls are not typically used in this industry. This analysis suggests that additional add-on control may not be required as BACT for NO_x emissions from the VAC production process.

Clay Brick Industry

Finally, the brick industry is similar to the VAC production process in that nonmetallic minerals are used as a feedstock. In the brick industry, clays (which are often mined in geologic formations that contain coal) are wetted and formed into bricks then fired in kilns at high temperature to drive off moisture from the brick and create the final product. From the dryer, the bricks enter the kiln for firing. There are several steps to firing the bricks in the kiln; evaporation of free water, dehydration, oxidization, and flashing. Flashing refers to the process of introducing uncombusted fuel into the kiln atmosphere in order to add color to the surface of the bricks. Most kilns are fired with natural gas, although coal, sawdust, fuel oil, and landfill gas are also used. Once the bricks have been fired, they are then cooled to ambient temperatures before they leave the kiln. Kiln fuel combustion and some dryer combustion activities result in the production of NO_x emissions. In a manner similar to the VAC process, a small proportion of the raw clay material used in brick production combusts as fuel during the firing process, resulting in NO_x emissions. NO_x emissions from brick production processes are generally the same order of magnitude as those in the VAC process. As in the VAC industry, the brick industry is a “low margin” industry and the installation of add-on controls may compromise the viability of a particular plant. Many brick plants do not have add-on controls for NO_x. This analysis suggests that add-on control may not be required for NO_x emissions from the VAC production process to meet BACT.

The RBLC clearinghouse was then searched for BACT determinations for similar processes as described above using the search terms: calciner; brick manufacturing; calcined carbon; calcined coke; and carbon black. The search returned results for only the terms “carbon black” and “calciner”. The Columbian Chemicals Corporation operates a carbon black reactor that minimizes the production of NO_x emissions with good combustion practices. Degussa Engineered Carbons Corporation (DEC) operates several carbon black reactors for which a PSD-BACT review was performed. For these facilities, NO_x controls were determined to be technically infeasible. The search for “calciner” provided results for several cement manufacturing companies and a soda ash production company. The results indicated instances of preheaters and calciner kilns for which NO_x emissions were controlled through the use of either

good combustion practices or low- NO_x burners. One cement company used the combination of a low NO_x burner with selective non-catalytic reduction in their kiln.

RBLC search results for the previous categories follow. These lists identify the companies and processes found. BACT requirements, if any, have been discussed in the preceding paragraphs. More details may be found in Appendix A of the permit application.

All RBLC Determinations for Process containing Carbon Black and NO_x

| RBLC ID | Facility | State | Update | Process Type | Process Type |
|---------|---------------------------------|-------|------------|--|--------------|
| OH-0287 | Degussa Engineered Carbons | OH | 5/27/2004 | Rotary Tailgas And Natural Gas-Fired Dryer | 69.015 |
| AR-0045 | Columbian Chemicals - El Dorado | AR | 12/12/2002 | Carbon Black Mfg., Units A, B, & C | 69.015 |

All RBLC Determinations for Process containing Carbon and NO_x

| RBLC ID | Facility | State | Update | Process Type | Process Type |
|---------|---|-------|------------|--|--------------|
| KY-0070 | NSA-A Division of Southwire Company | KY | 5/29/1998 | Carbon Bake Furnace | 19.600 |
| KY-0078 | Meadwestvaco Kentucky LP - Wickliffe Carbon Plant | KY | 11/16/1999 | Woodbase Carbon Acid/Mixing, Activation Kiln | 69.999 |
| KY-0078 | Meadwestvaco Kentucky LP - Wickliffe Carbon Plant | KY | 11/16/1999 | Drying Kiln, Specialty Thermal Carbon | 19.600 |
| CO-0040 | American Soda, LLP, Parachute Facility | CO | 5/6/1999 | Sodium Carbonate Prod., Soda Ash Dryer, Nat. Gas | 62.018 |

All RBLC Determinations for Process containing Calciner and NO_x

| RBLC ID | Facility | State | Update | Process Type | Process Type |
|---------|---|-------|------------|--|--------------|
| IA-0070 | Lehigh Cement Company - Mason City Plant | IA | 12/11/2003 | Kiln/Calciner/Preheater | 90.028 |
| IA-0052 | Lafarge Corporation | IA | 7/1/2002 | Cement Manufacturing Preheater/Precalciner Kiln | 90.028 |
| CO-0043 | Rio Grande Portland Cement Corporation | CO | 9/25/2000 | Preheater/Precalciner, Kiln | 90.028 |
| MD-0027 | Lehigh Portland Cement Company | MD | 6/8/2000 | Cement Manufacturing, Preheater/Precalciner Kiln | 90.028 |
| KS-0022 | Monarch Cement Company | KS | 1/27/2000 | 2 Precalciners (each) | 90.028 |
| WY-0034 | Solvay Soda Ash Joint Venture Trona Mine/Soda Ash | WY | 2/6/1998 | Calciner, Natural Gas Fried Trona | 90.017 |

All RBLC Determinations for Process containing Activation Furnace and NO_x

| RBLC ID | Facility | State | Update | Process Type | Process Type |
|---------|--|-------|------------|-----------------------------|--------------|
| AL-0205 | Anniston Chemical Agent Disposal Facility Field Office | AL | 12/28/2004 | Deactivation Furnace System | 21.2 |
| AL-0178 | Anniston Army Depot - Chemical Weapons Incinerator | AL | 1/9/2003 | Deactivation Furnace | 21.2 |
| TX-0361 | Equistar Chemicals, | TX | 1/5/2005 | Cat. Reactivation Furnace | 19.6 |

The next step consists of searching the EPA RBLC database for similar emissions units. Due to the unique nature of the thermal VAC production process, the RBLC database did not include any “similar” emission units. Therefore, for the purposes of this BACT analysis, a coal-fired boiler was considered to be a similar emission unit even though there are fundamental differences between carbonizers and coal-fired boilers. The primary difference is that in a coal fired boiler, the coal is almost completely consumed to provide heat. In VAC manufacturing, the process seeks to preserve the majority of the carbon in the coal and achieve the desired structure. Far less coal is combusted in a VAC process than in a similarly sized coal-fired boiler, resulting in much lower generation of NO_x from combustion. A secondary difference is that the capacity of coal fired boilers is typically far higher than that of the carbonizers used by the NORIT Pryor Facility. Large coal fired boilers are expected to have a significantly higher emissions potential because the coal consumption of one 250 MMBtu/hr coal fired boiler is almost double the amount of coal used at the NORIT Pryor facility. The difference in emissions potential is significant not only on a mass emissions basis, but also on a pollutant concentration basis in that the exhaust of a coal-fired boiler is expected to have higher NO_x emissions than the exhaust from a similarly-sized VAC process due to coal being the main source of fuel for a coal fired boiler, unlike the VAC process. This makes control methods more feasible for the boilers and not as feasible for the VAC process.

Despite these differences, coal fired boilers and VAC manufacturing both use coal as a raw material and the RBLC was searched for BACT determinations for coal fired boilers. Of the results returned for process type 11.110, coal-fired large utility boilers / furnaces (capacity greater than 250 million British thermal unit per hour (MMBtu/hr)), 29 coal fired boilers were identified in the RBLC database. The nitrogen oxide controls and/or control technologies that were determined to be BACT-PSD at the time of permitting action included six boilers with selective non-catalytic reduction / good combustion practices (one facility installed a CEM for monitoring), two boilers with low NO_x burners/ good combustion practices, 6 boilers with low NO_x burners/ Selective Catalytic reduction, one boiler with low NO_x burners/ Selective Non-catalytic reduction, five boilers with Selective catalytic reduction, and two boilers with good combustion practices. The remaining seven boilers under the large utility boilers process type were not specifically noted as having nitrogen dioxide control required as BACT-PSD. These seven determinations were marked “N/A”, NSPS, or “other case-by-case determination.” The controls and/or control technologies on these boilers were: one boiler with selective non-catalytic reduction; one boiler with low NO_x burners/ good combustion practices; one boiler with low NO_x burners combined with selective non-catalytic reduction; one boiler with a CEM for NO_x monitoring; and three boilers with no feasible controls.

A search was also performed on industrial sized boilers and furnaces (capacity between 100 and 250 MMBtu/hr) that were included in the RBLC database. The search returned three boilers in this category, showing one boiler with selective non-catalytic reduction and two boilers with good combustion practice determined to be BACT-PSD at the time of the permitting action. Finally, a search was conducted for commercial / institutional size boilers (capacity less than 100 MMBtu/hr). No search results were returned for this category.

RBLC search results for the previous categories follow. These lists identify the companies and processes found. BACT requirements, if any, have been discussed in the preceding paragraphs. More details may be found in Appendix A of the permit application.

**All RBLC Determinations for Process Code 11.110
Large Coal Fired Boilers > 250 MMBTUH and SO2**

| RBLC ID | Facility | State | Update | Process Type |
|----------------|---|--------------|---------------|--|
| ND-0024 | Great River Energy Spiritwood Station | ND | 9/14/2007 | Atmospheric Circulating Fluidized Bed Boiler |
| UT-0070 | Desert Power Electric Cooperative Bonanza Power Plant Waste Coal Fired Unit | UT | 8/30/2007 | Circulating Fluidized Bed Boiler 1445 |
| OK-0118 | Western Farmers Electric Corporation Wygen 3 | OK | 2/9/2007 | Coal-Fired Steam Boiler (Unit 2) |
| WY-0063 | Black Hills Corporation | WY | 2/5/2007 | Boiler |
| NE-0041 | Ag Processing, Inc. Agp Soy Processing | NE | 9/11/2006 | Unit 3 Boiler |
| WV-0024 | Western Greenbrier Co- Generation | WV | 4/26/2006 | Circulating Fluidized Bed Boiler |
| MO-0071 | Great Plains Energy Kansas City Power & Light Company | MO | 1/27/2006 | Pulverized Coal Boiler |
| MO-0071 | Great Plains Energy Kansas City Power & Light Company | MO | 1/27/2006 | Pulverized Coal Boiler Unit 2 |
| TX-0518 | Valero Refining - Valero Heavy Oil Cracker | TX | 11/16/2005 | Emissions |
| VA-0296 | Virginia Polytechnic Institute and State University | VA | 9/15/2005 | Operation Of Boiler |
| LA-0176 | Louisiana Generating, | LA | 8/22/2005 | New 675 Mw Pulverized Coal Boiler |
| ND-0021 | Montana Dakota Utilities/Westmoreland Power Gascoyne Generating Station | ND | 6/3/2005 | Boiler-Coal-Fired |
| NV-0036 | Newmont Nevada Energy Investment | NV | 5/5/2005 | Coal Boiler |
| NE-0031 | Omaha Public Power District | NE | 3/9/2005 | Unit 2 Boiler |
| MO-0060 | City Utilities of Springfield - Southwest Power Station | MO | 12/15/2004 | Pulverized Coal Fired Boiler |
| WI-0228 | Wisconsin Public Service Wps - Weston Plant | WI | 10/19/2004 | Super Critical Pulverized Coal Electric Steam Boiler |
| UT-0065 | Intermountain Power Service Corporation - Power Generating Station | UT | 10/15/2004 | Pulverized Coal Fired Electric Generating Unit |
| UT-0064 | Nevco - Sevier Power Company | UT | 10/12/2004 | Boiler With Dry Lime Scrubber |
| NE-0018 | Hastings Utilities Whelan Energy Center | NE | 3/30/2004 | Boiler, Unit 2 Utility |
| WV-0023 | Longview Power | WV | 3/2/2004 | Boiler, |
| SC-0104 | Santee Cooper Cross Generating Station | SC | 2/5/2004 | Boiler No. 3 And No. 4 |
| WI-0225 | Manitowoc Public Utilities | WI | 12/3/2003 | Circulating Fluidized Bed Boiler (Electric Generation) |
| AR-0079 | Plum Point Associates | AR | 8/20/2003 | Boiler |
| OH-231 | First Energy Toledo Edison Co. | OH | 7/31/2003 | Boiler, Coke/Coal-Fired |
| TX-0491 | Black Hills Corporation | TX | 2/5/2007 | No. 6 Power Boiler |
| TX-0489 | Southwestern Public Service Company | TX | 10/17/2006 | Unit 3 Boiler |
| TX-0499 | Sandy Creek Energy Associates | TX | 7/24/2006 | Pulverized Coal Boiler |
| MO-0071 | Great Plains Energy Kansas City Power & Light Company | MO | 1/27/2006 | Pulverized Coal Boiler Unit 1 and Unit 2 |

**All RBLC Determinations for Process Code 12.110
Large Coal Fired Boilers <250 MMBTUH and SO₂**

| RBLC ID | Facility | State | Update | Process Type |
|----------------|--|--------------|---------------|-------------------------|
| ND-0020 | Red Trail Energy, LLC Richardson Plant | ND | 8/4/2004 | Boiler, Coal Fired |
| VA-0267 | VPI University Power Station | VA | 8/30/2001 | Boiler, Overfeed Stoker |
| OH-0241 | Miller Brewing Company – Trenton | OH | 5/27/2007 | Boiler, (2) Coal Fired |

Because the results of the RBLC searches were very limited, additional permitting documentation for the VAC process and similar processes was reviewed. The documentation reviewed includes supporting permit documentation that is publicly available. The results of this review are presented in the following subsections.

Virgin Activated Carbon Manufacturing

Because the thermal VAC process is a relatively unique process in the United States, it was not surprising that the RBLC clearinghouse did not contain a VAC emission unit or process specific BACT determinations. At the time of this BACT review, only three United States facilities use the thermal re-agglomeration (TA) process to produce VAC. TA VAC production facilities in the United States include the Calgon Carbon Corporation's Catlettsburg, Kentucky and Bay St. Louis, Mississippi facilities, and the Pryor Facility. As previously mentioned, the RBLC clearinghouse did not contain any determinations for these facilities. Therefore, additional permit documents outside of the RBLC clearinghouse and that are publicly available were reviewed. The permitting information gathered for the Calgon facilities indicated that the carbonizers did not contain any controls for NO_x. The Title V Permit for the Calgon Catlettsburg Facility represents a synthetic minor limit for NO_x on their activation furnaces, which are not equipped with any add-on control devices. As an additional point of reference, NORIT also owns and operates a thermal VAC process in Marshall, Texas. Although VAC is produced by a thermal process at the Marshall Facility, the process is inherently different in that it is a direct activation process, not a reagglomeration process. The NORIT Marshall VAC process has modified their process to a post-treated process in the MHF, resulting in lower NO_x and SO₂ emissions than in typical processes. No add-on NO_x emission controls have been installed at the Marshall Facility, although it should be noted that a PSD permit and a BACT determination were not required at the time of this modification. The Marshall facility typically minimizes NO_x emissions by processing coal with good combustion practices.

Therefore, of the three VAC facilities discussed herein, none of them employed add-on NO_x emission controls. However, several facilities were required to employ good combustion practices by the operational limitations section of their permits. Therefore, good combustion practices appear to be considered BACT for NO_x emission control from a VAC process.

Because the RBLC searches for similar processes did not produce any results for NO_x controls for VAC processes, additional permit documentation was reviewed to identify controls in place for similar processes. This review identified three additional permitting actions for Degussa Carbon Black Plant in Baytown, Texas, Oxbow Carbon in Port Arthur, TX and Seadrift Carbon in Port Lavaca, TX that are relevant to this BACT analysis. The Degussa Carbon Black Plant (DEC) in Baytown, Texas produces carbon black from an oil feedstock. This facility voluntarily self-disclosed historical NO_x exceedances in their permit. As a result, the facility entered into a Compliance Agreement with the Texas Natural Resource Conservation Commission (TNRCC). Pursuant to a voluntary compliance audit performed by DEC under the Texas Environmental, Health, and Safety Audit Privilege Act, three issues related to emissions testing were disclosed

by DEC. The disclosed issues included descriptions of instances in which total NO_x emissions from the facility exceeded the maximum allowable emission rates in Permit No. 9294. Historical emission rates were calculated based on invalid technical assumptions and inappropriate emission factors. Since historical NO_x emissions were under-represented by DEC, a retroactive PSD review of the previous projects was required. The projects undertaken by DEC since 1992 fell under the definition of pollution control projects and therefore did not require nonattainment NSR/PSD review since the increases do not contribute to an exceedance of the NAAQS. Therefore, nonattainment review was not required as part of this Compliance Agreement. No source reduction activities have been proposed for NO_x emissions from this facility. The NO_x emissions potential for this facility is generally comparable to that of the Pryor Facility. The DEC facility was not equipped with add-on NO_x controls and Baytown subsequently shutdown all combustion units in August 2003.

Oxbow Carbon LLC, located in Port Arthur, Texas, is a calcining coke production plant that processes almost one million pounds of green coke a year. In 2006, Oxbow proposed new emission rates for Process Kiln 5 with a submittal of a Pollution Control Project standard permit, including proposed NO_x emission rates exceeding 2,200 tons of NO_x per year. This emissions potential is based on a review of the Maximum Allowable Emissions Rate Table (MAERT) for Texas Commission on Environmental Quality (TCEQ) permit numbers 5421 and 45622. The processing capacity of this facility is almost two orders of magnitude greater than the Pryor Facility and the emissions potential is almost 3 times the current emissions at the Pryor Facility. No add-on NO_x controls were required by, or discussion of good combustion practices were included, within the requirements of the above referenced permits.

Finally, permit documentation for needle coke manufacturing was reviewed. Recent permitting documentation for the expansion of Seadrift Carbon in Port Lavaca, TX was located and reviewed. Seadrift Carbon increased their permitted calcining capacity from 27 tons per hour to 40 tons per hour. Process heaters at the facility were determined not to meet current BACT, but TCEQ agreed to allow them to meet 10 year old BACT because retrofit of the burners with controls could not be achieved without adversely affecting their product. Their unique process has allowed them to operate with the preexisting (i.e., non-low NO_x) burners.

The review of additional permit documentation for similar processes revealed that 'no control' has been considered BACT for these processes. However, good combustion practices have been adopted to help reduce NO_x emissions. These facilities process more raw material and have a higher emissions potential than the Pryor Facility and add-on NO_x controls have not been required.

Available Control Technologies

Based on the review of BACT determinations archived in the RBLC clearinghouse as well as additional permitting documentation, the following list of available control technologies was generated. These control technologies will be reviewed in the remaining steps of the top-down BACT review.

- Selective non-catalytic reduction
- Selective catalytic reduction
- Low- NO_x burners
- Good combustion practices

Step 2 – Eliminate Technically Infeasible Options

While several of the available control options are technically challenging or have significant adverse economic or environmental impacts, none of them is technically infeasible. Adverse impacts are discussed in more detail below.

Step 3 – Rank Remaining Control Options Based on Effectiveness

Following is a discussion of each add-on control option, presented in order based on their efficiency from an emission control perspective: (1) selective catalytic reduction; (2) selective non-catalytic reduction; and (3) Low- NO_x burners.

5.3.2 Selective Catalytic Reduction

Selective Catalytic Reduction (SCR) has been applied to stationary source fossil fuel-fired combustion units for emission control since the early 1970s and is currently being used in utility industrial boilers, process heaters, and combined cycle gas turbines. In the United States, systems of this type are commonly used for coal- and natural gas-fired electrical utility boilers ranging in size from 250 to 8,000 MMBtu/hr (25 to 800 megawatts (MW)). SCR can be applied as a stand-alone NO_x control or with other technologies such as combustion controls (e. g. Low-NO_x Burners).

SCR is typically implemented on stationary source combustion units requiring a higher level of NO_x reduction than achievable by SNCR or combustion controls. Theoretically, SCR systems can be designed for NO_x removal efficiencies up to 100 percent (%). Commercial coal-, oil- and natural gas-fired SCR systems are often designed to meet control targets of over 90%. However, maintaining this efficiency is not always practical from a cost standpoint. In practice, SCR systems operate at efficiencies in the range of 70% to 90%. Like SNCR, the SCR process is based on the chemical reduction of the NO_x molecule. The primary difference between SNCR and SCR is that SCR employs a metal-based catalyst with activated sites to increase the rate of the reduction reaction. A nitrogen-based reducing agent (reagent), such as ammonia or urea, is injected into the post combustion flue gas. The reagent reacts selectively with the flue gas NO_x within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NO_x into molecular nitrogen (N₂) and water vapor (H₂O). The use of a catalyst results in two primary advantages of the SCR process over SNCR. The main advantage is the higher NO_x reduction efficiency. In addition, SCR reactions occur within a lower and broader temperature range. However, the decrease in reaction temperature and increase in efficiency is accompanied by a significant increase in capital and operating costs. The cost increase is mainly due to the large volumes of catalyst required for the reduction reaction.

Selective Non-catalytic Reduction

Selective non-catalytic reduction (SNCR) utilizes a reagent (typically ammonia or urea) to selectively reduce NO_x emissions through the chemical reduction of NO_x into molecular nitrogen (N₂) and water vapor (H₂O). SNCR is currently being used for NO_x emission control on industrial boilers, electric utility steam generators, thermal incinerators, and municipal solid waste energy recovery facilities. It has been demonstrated that SNCR can be applied as a stand-alone NO_x control or with other technologies such as combustion controls. An SNCR system can be designed for seasonal or year-round operations. SNCR can achieve NO_x reduction efficiencies of up to 75 percent (%) in selected short-term demonstrations. In typical field applications, however, it provides 30% to 50% NO_x reduction. Reductions of up to 65% have been reported for some field applications of SNCR in tandem with combustion control equipment such as low NO_x burners. SNCR systems applied to large combustion units (greater

than 3,000 MMBtu/hr) typically have lower NO_x reduction efficiencies (less than 40%), due to mixing limitations.

So far, only limited testing of SNCR has been conducted. SNCR technology is applicable to preheater/precalciner type kilns with limited data indicating its effectiveness. SNCR is not considered applicable to long wet and dry kilns due to difficulties involved in continuous injection of reducing agents. There have been a few demonstrations of SNCR at preheater/precalciner kilns. Molar reagent ratio, temperature, and gas residence time in the appropriate temperature window are primary factors affecting NO_x reduction efficiency. As indicated above, no known SNCR systems have been installed as control devices for VAC processes. Therefore, their effectiveness in reducing NO_x emissions in VAC production applications is unknown.

Low- NO_x Burners

Low- NO_x burners are a type of gas burner that significantly reduces the formulation of NO_x molecules from the combustion of gaseous fuels (e.g., natural gas, etc.). Low- NO_x burners are often considered to be BACT on many types of large (i.e., greater than 250 MMBtu.hr) coal-fired boilers and other large combustion devices. Typically, these processes use large amounts of gaseous fuel to directly heat a vapor or indirectly heat a liquid space in which no subsequent combustion activity occurs. In the VAC process, the combustion of natural gas is used to indirectly heat the carbonizer reaction space and create the correct conditions for the carbonization of the coal raw material. Compared with the proportion of NO_x emissions that result from the combustion of the coal raw material within the carbonizers and the formulation of NO_x molecules from thermal reaction in the vapor space in the carbonizer, NO_x formulation from the combustion of natural gas is considered insignificant. Low-NO_x burners might therefore be considered to significantly reduce NO_x emissions from VAC processes only when used in conjunction with SCR or SNCR systems, which can achieve very high levels of NO_x reduction. The exclusive use of low- NO_x burners for NO_x reduction from VAC systems without additional control by SCR or SNCR systems is not considered in this analysis.

5.3.4 Good Combustion Practices

Although not an add-on control technology, good combustion practices for combustion sources in VAC manufacturing was evaluated as BACT. Available information indicates that good combustion practices is one of the most widely used NO_x reduction techniques, and is the only method used to control NO_x emissions in the VAC manufacturing processes reviewed above. Good combustion can be practiced with the use of a standard operating procedure, detailed and planned maintenance schedules, and overall good operations from the facility. NO_x emissions, (typically greater than 95% NO and less than 5% NO₂, are primarily a consequence of the high combustion temperatures present in reaction spaces such as carbonizers and cement kilns (which can reach approximately 2000°C in the flame zone) that allow nitrogen in the vapor space to react with oxygen molecules. Small contributions to NO_x generation also come from the reaction of nitrogen compounds contained in the solid fuels themselves. Primary NO_x reduction can occur through optimization of the burning process and of the main burner. The various optimization techniques require certain conditions to be effective, therefore NO_x reduction measures are tailored according to characteristics of the plant and its environment. Good combustion practices are defined according to how the facility operates its combustion sources and how efficient they are in doing so. The following table summarizes selected Good

Combustion Techniques as defined by US EPA that are currently in use or may potentially be considered for use the NORIT Pryor Facility.

Examples of Good Combustion Techniques

| Good Combustion Techniques | Examples of Practices |
|--|---|
| Operator practices | -Official documented operating procedures, updated as required for equipment or practice change, -Procedures include startup, shutdown, malfunction -Operating logs/record keeping |
| Maintenance knowledge | -Training on applicable equipment & procedures |
| Maintenance practices | -Official documented maintenance procedures, updated as required for equipment or practice change -Routinely scheduled evaluation, inspection, overhaul as appropriate for equipment involved -Maintenance logs/record keeping |
| Stoichiometric (fuel/air) ratio | -Burner & control adjustment based on visual checks -Burner & control adjustment based on continuous or periodic monitoring (O ₂ , CO, CO ₂) -Fuel/air metering, ratio control -Oxygen trim control - Safety interlocks |
| Fuel/waste quality (analysis); fuel/waste handling | -Monitor fuel/waste quality -Fuel quality certification from supplier if needed -Periodic fuel/waste sampling and analysis -Fuel/waste handling practices |
| Combustion air distribution | -Adjustment of air distribution system based on visual observations -Adjustment of air distribution based on continuous or periodic monitoring |
| Fuel/waste dispersion | -Adjustment based on visual observations |

Step 4 – Evaluate Most Effective Controls

According to top-down BACT protocol, the control options must be evaluated from most to least stringent control option. The most stringent control option that is not rejected is determined to be BACT. This section documents the review of the control options in the rank order determined in Step 3.

Selective Catalytic Reduction

Environmental Impacts

In addition to similar impacts as described for SNCR systems in the following section, SCR catalysts are composed of active metals or ceramics with a highly porous structure. There are activated sites within the pores of the catalyst. These sites have an acid group on the end of the compound structure where the reduction reaction occurs. As discussed in the SNCR section below, after the reduction reaction occurs, the site reactivates via rehydration or oxidation. Over time, however, the catalyst activity decreases, requiring replacement of the catalyst. The periodic replacement of solid catalyst produces an additional solid waste that would require additional handling. The management, treatment, and/or disposal of spent catalyst waste could potentially create new particulate matter (PM) emissions from the NORIT Pryor Facility or the offsite facility that receives the waste catalyst.

Economic Impacts

The main economic impact of using the SCR system is that the decrease in reaction temperature and increase in efficiency realized over similar SNCR systems is accompanied by a significant increase in capital and operating costs. The cost increase is primarily due to the large volumes of

catalyst required for the reduction reaction. A catalyst management plan is required to determine the precise amount of catalyst needed to achieve the desired NO_x reduction efficiency, as well as defining the schedule for reactivation or replacement of the catalyst when necessary.

Retrofitting existing equipment with SCR has higher capital costs than installing SCR on new process equipment. The magnitude of the cost differential is a function of the difficulty of the retrofit. The increase in cost is primarily due to making the modifications required to existing ductwork, the cost of structural steel and the construction of the reactor, auxiliary equipment costs (i.e., additional fans), and engineering costs. In addition, significant demolition and relocation of equipment may be required to provide space for the reactor. These costs can account for over 30% of the capital costs associated with SCR. The annualized cost of control for the operation of a SCR system was calculated to be \$494,494 per year. An approximately 50% reduction in NO_x generation rates (i.e., from 0.39 lb/MMBtu to 0.20 lb/MMBtu) would result in a 37 tpy reduction of NO_x emissions, based on the maximum production rates identified elsewhere in this Memorandum. The resultant cost effectiveness for this control system is \$13,353 per ton. Detailed calculations for the annualized cost and cost effectiveness are contained in Appendix B of the application.

Taking into account the significant operating cost, site-specific energy, environmental, and economic impacts, SCR is rejected as BACT for the carbonizers at the Pryor Facility.

Selective Non-catalytic Reduction

Environmental Impacts

The environmental drawbacks to the use of an SNCR system include the production of greenhouse and ozone-depleting gases, the production of visible emissions and odor concerns that may affect the quality of life of the local population, and the safety, health and environmental concerns regarding the use of ammonia gas. The primary byproduct formed from the use of ammonia or urea as a reagent is a significant quantity of nitrous oxide, which is an ozone depleting gas and a greenhouse gas. Ammonia has a detectable odor at levels of 5 ppm or greater and poses a health concern at levels of 25 ppm or greater. It can cause a stack plume visibility problem by the formation of ammonium chlorides that occur when burning fuels containing chlorine compounds. Furthermore, ammonium bisulfate and ammonium sulfate form when burning sulfur-containing fuels. Ammonia-sulfur salts can plug, foul, and corrode downstream equipment such as air heater, ducts, and fans. Additionally there is a safety concern of the use of ammonia in the form of anhydrous ammonia. Anhydrous ammonia is a gas at normal atmospheric temperature. It must be transported and stored under pressure, which presents safety issues as it is a highly flammable material. Ammonia is generally injected as a vapor. The injection system equipment for vapor systems is more complicated and expensive than equipment for aqueous (i.e., urea) systems. Urea-based systems have several advantages over ammonia-based systems. Urea is a nontoxic, less volatile liquid that can be stored and handled more safely than ammonia. Urea solution droplets can penetrate farther into the flue gas when injected. This enhances mixing with the flue gas, which is difficult on large systems. Because of these advantages, urea is used more commonly than ammonia in large boiler applications of SNCR systems. Although this is an advantage over ammonia, the use of urea does pose higher economic costs as described below.

Economic Impacts

The use of urea is generally utilized in a 50% aqueous solution. At this concentration, the urea solution must be heated and circulated in cold climates due to its high freezing point, 17.8°C (64°F). Higher-concentration urea solutions that decrease the storage volume are available, but

require extensive heating to prevent freezing. Urea is injected into a system as an aqueous solution and vaporized by the heat contained in the vapor space of the reactor (i.e., carbonizer). Urea can also be transported in pellet form that minimizes transportation requirements. However, to produce aqueous urea for use in the SNCR system, the urea must then be mixed with additional water at the facility. This mixing process is generally cost prohibitive except for remote sites, large facilities, or facilities where chemical mixing processes are already being performed. As the NORIT Pryor facility does not fall into one of the abovementioned categories, it is determined that the addition of mixing facilities to the current site will result in significant cost requirements. As mentioned above, the use of ammonia can also cause significant economic impacts over the use of urea-based systems. These additional costs include additional equipment necessary to safely and securely store the ammonia, as well as the additional maintenance and repair required on the carbonizer due to the generation of ammonia sulfur salts that become deposited on equipment internals.

The annualized cost of control for the operation of a SNCR system was calculated to be \$314,000 per year. An approximately 50% reduction in NO_x generation rates (i.e., from 0.39 lb/MMBtu to 0.20 lb/MMBtu) would result in a 37 tpy reduction of NO_x emissions, based on the maximum production rates identified elsewhere in this Memorandum. The resultant cost effectiveness for this control system is \$8,479 per ton. Detailed calculations for the annualized cost and cost effectiveness are contained in Appendix B of the permit application. As previously mentioned, the costs above do not take into consideration the costs for heating and circulation of the urea material for cold climates due to its high freezing point or additional costs required for the safe and secure storage and handling of ammonia.

The RBLC clearinghouse revealed that cost effectiveness data is not recorded for the majority of the determinations archived in the database and for none of the RBLC determinations that identified SNCR as the control device. Of all of the facilities that had SNCR as a control system for NO_x reduction, only one of them quoted a cost effectiveness of \$4,748 to reduce NO_x to 0.08 lb/MMBtu. A summary of the RBLC determinations that contained cost effectiveness data is included in Appendix A of the permit application.

Taking into account the significant operating cost, site-specific energy, environmental, and economic impacts, SNCR is rejected as BACT for the carbonizers at the Pryor Facility.

Low- NO_x Burners

Low- NO_x burners are add-on control systems designed to facilitate staged combustion and minimize NO_x emissions. The installation of low- NO_x burners involves a modification of the primary combustion process (staged combustion). As discussed above, low- NO_x burners alone are not considered to be a viable pollution control measure for VAC processes. Therefore, an evaluation of low- NO_x burners operated in conjunction with SNCR or SCR has been made. The NO_x reduction potential of these two low- NO_x burner systems (i.e., SNCR/Low- NO_x and SCR/Low- NO_x), as well as the associated capital costs, operating and maintenance impacts, and required outage for retrofit are summarized below.

Environmental Impacts

The use of Low- NO_x burners in general can increase the formation of CO in exhaust gases due to an increase in incomplete fuel combustion versus complete fuel combustion. Additionally, several burner manufacturers have developed low NO_x systems with mixed results. Modern low- NO_x burners must be specifically designed for a particular application and will not control

emissions in different combustion systems or under different conditions because of their inflexibility. Therefore, low- NO_x burners must be specially constructed for their purpose or will not result in any emissions reductions. It is not known if low- NO_x burners suitable for application in VAC processes are currently available from existing manufacturers, or if a custom-designed low- NO_x burner will be required.

Economic Impacts

The effectiveness of Low- NO_x burners, especially for retrofit cases, depends on a number of site-specific parameters. Low- NO_x burners are generally larger than conventional burners and require more precise control of fuel/air distribution. Their performance depends partially on increasing the size of the combustion zone to accommodate longer flames. Because of this, Low- NO_x burners are expected to be less effective when retrofitted on relatively small applications. In some cases, existing piping and/or other structures must be reconfigured to allow additional room for the new burners, requiring additional cost. Low- NO_x burners may also have longer flames that may impinge on the opposite wall, which can result in operation or safety issues in some vessels. Potential solutions to flame impingement include adjusting velocities of the fuel or primary air, adjusting secondary air, and/or reconfiguring vulnerable internals. Vessels with very small volumes may have to be de-rated in order to prevent flame impingement at full load.

Another cost consideration that must be considered when retrofitting with Low- NO_x burners is modifications to the windbox. These windbox modifications may include the addition of dampers and baffles for better control of combustion air flow to burner rows and combustion air distribution to burners within a row. Also, the windbox must be large enough to accommodate the Low- NO_x burners. If the existing windbox requires substantial modifications to structural components, major re-piping, and/or windbox replacement, retrofitting Low- NO_x burners may not be economically feasible.

Official US EPA or state guidance for conducting a cost analysis for the retrofitting of low- NO_x burners, including the calculation of direct, indirect, and operational costs was not available. A search of historical projects indicated that the cost of installing a Low- NO_x burner system can range from \$24,000 up to \$2,000,000 depending on the size and age of the combustion vessel. Yearly operational costs can be as much as \$20,000/year. Based on these figures, it is estimated that NO_x removal can cost approximately \$10,000/ton to control NO_x emissions from carbonizer processes similar to those in use at the NORIT Pryor facility. As previously indicated, the cost effectiveness data available in the RBLC clearinghouse reveals several determinations for the use of Low- NO_x burners for controls, but it did not give a cost determination of their use. The use of Low- NO_x burners in a carbonizer system without additional add-on NO_x control would not be beneficial. The Low- NO_x burners would need to be used in conjunction with a SNCR or SCR system to achieve the NO_x level desired. The estimated cost for a SNCR or SCR, without additional site specific considerations that would increase the capital and annualized costs, are more than an order of magnitude higher than the cost effectiveness indicated as BACT in the RBLC clearinghouse.

Taking into account the site-specific economic and environmental impacts, low NO_x burner add-on systems are rejected as BACT for the carbonizers at the Pryor Facility, primarily as a function

of the high cost of this system when installed in combination with a SNCR or SCR system to control NO_x emissions from the reaction space of the carbonizers.

Step 5 – Selection of BACT

NORIT does not believe that any of the add-on control technologies discussed above is feasible for limiting NO_x emissions from the carbonizers for reasons cited in each of the analyses above. Good combustion practice is used widely in the VAC production industry to reduce emission of NO_x and other pollutants that result from improper or inefficient combustion.

As specified in the EPA's Top-Down BACT protocol, the most stringent control option not eliminated is selected as BACT. Therefore, good combustion practices in the operation of the carbonizers is selected as BACT. This will have the effect of limiting emissions from the primary and secondary carbonizer without incurring prohibitive costs or adverse environmental impacts, as would be the case for an add-on control technology. NO_x emission limits of 49.27 tpy and 183.96 tpy are proposed from the primary and secondary carbonizers, respectively, as described earlier in this Memorandum.

A. BACT for SO₂

Step 1 – Identification of all available control options

The discussion of this step is very similar to the language used for the NO_x review. Process descriptions and other material are not repeated. Only language specific to SO₂ is stated.

Carbon Black Industry

As above. The tail gas contains a significant quantity of reduced sulfur compounds that are driven from the sulfur in the feedstock. In order to reduce the quantity of reduced sulfur compounds emitted to the atmosphere, the tail gas is subsequently combusted in a thermal oxidizer, flare or other combustion device in a manner similar to the way the exhausts from the VAC process are combusted in the afterburners. The combustion of the sulfur compounds results in a significant quantity of SO₂ emissions. The SO₂ emissions from the carbon black process are typically orders of magnitude higher than those seen in the VAC production process and add-on SO₂ emission controls have not been required by regulatory agencies or by the recent federal regulations promulgated by EPA. Therefore, additional add-on control may not be required for the waste gases from the VAC production process to meet BACT.

Calcined Coke Industry

As above. The petroleum coke typically contains significant quantities of bound sulfur that is driven off during calcining. The resulting tail gases from this process, therefore, contains significant quantities of SO₂ that are orders of magnitude higher than those seen in the VAC production process and add-on SO₂ control is not used in this industry. Therefore, additional add-on control may not be required for the waste gases from the VAC production process to meet BACT.

Petroleum Coke Industry

As above. The petroleum coke typically contains significant quantities of bound sulfur that is driven off in the kilns. The resulting tail gases from this process, therefore, contain significant quantities of SO₂ that are orders of magnitude higher than those seen in the VAC production process. Similar to the calcined coke industry, add-on SO₂ control is not used. Therefore, additional add-on control may not be required for the waste gases from the VAC production process to meet BACT.

Clay Brick Industry

As above. In a similar manner to the VAC process, the clay raw material used for brick production contains sulfur that is driven off during the firing process resulting in SO₂ emissions. SO₂ emissions from brick production are generally the same order of magnitude as those in the VAC process. As in the VAC industry, the brick industry is a “low margin” industry and the installation of add-on controls may compromise the economic viability of a plant. Although many brick plants do not have add-on controls for SO₂, a recent MACT standard promulgated by EPA has identified the need for hazardous air pollutant (HAPs) control from the brick kilns. One of the control technologies used, “dry lime injection” or “dry lime scrubbing”, also provides SO₂ control. In this control technology dry lime is added to the waste gases to react with the acid gases (hydrofluoric acid (HF) and hydrochloric acid (HCl)) in the waste stream. Although dry lime injection is primarily for HF and HCl control, there is also a realized SO₂ control efficiency.

The RBLC clearinghouse was searched for BACT determinations for similar processes as described above using the search terms: calciner; brick manufacturing; calcined carbon; calcined coke; and carbon black. The search returned results for only the terms “carbon black” and “calciner”. The Cabot Corporation operates a carbon black reactor that is controlled for emissions of sulfur oxides by limiting the sulfur in the carbon black oil feedstock to three percent (3%) on an annual basis. In this case, the use of a low sulfur feedstock constitutes a sulfur oxide “control device” via pollution prevention and was determined to be BACT-PSD on December 28, 2004.

The search for “calciner” provided results from the cement manufacturing industry. The results showed operations of preheaters and calciner dryers that controlled emissions of sulfur oxides with the use of either a scrubber or low sulfur in the feedstock. In this case, the use of a low sulfur feedstock also constitutes a sulfur oxide “control device” via pollution prevention and was determined to be BACT-PSD on December 28, 2004.

RBLC search results for the previous categories follow. These lists identify the companies and processes found. BACT requirements, if any, have been discussed in the preceding paragraphs. More details may be found in Appendix A of the permit application.

All RBLC Determinations for Process containing Carbon Black and SO₂

| RBLC ID | Facility | State | Update | Process Type | Process Type |
|---------|---|-------|------------|--|--------------|
| OH-0287 | Degussa Engineered Carbons | OH | 5/27/2004 | Rotary Tailgas And Natural Gas-Fired Dryer | 69.015 |
| OH-0287 | Degussa Engineered Carbons | OH | 5/27/2004 | Carbon Black Units 3 And 4 | 69.015 |
| OH-0287 | Degussa Engineered Carbons | OH | 5/27/2004 | Carbon Black Units 1 And 2 | 69.015 |
| TX-0389 | Degussa Engineered Carbons | TX | 12/31/2002 | Carbon Black Process Caps | 69.015 |
| TX-0435 | Cabot Corp. Development & Mfg. Ctr. | TX | 12/31/2002 | Reactor, Carbon Black | 69.015 |
| TX-0426 | Cabot Corp. Pampa Plant | TX | 12/16/2004 | Reactor, Carbon Black | 69.015 |
| TX-0436 | Degussa Engineered Carbons Borger Carbon Black Plant | TX | 12/30/2004 | Carbon Black Mfg | 69.015 |
| AR-0045 | Columbian Chemicals – El Dorado | AR | 12/12/2002 | Carbon Black Mfg., Units A, B, & C | 69.015 |
| TX-0426 | Cabot Pampa Plant | TX | 12/16/2004 | Reactor, Carbon Black | 69.015 |

RBLC Search Conducted: All RBLC Determinations for Process containing Carbon and SO_x

| RBLC ID | Facility | State | Update | Process Type | Process Type |
|---------|-------------------------------------|-------|-----------|---------------------|--------------|
| KY-0070 | NSA-A Division of Southwire Company | KY | 5/29/1998 | Carbon Bake Furnace | 19.600 |

RBLC Search Conducted: All RBLC Determinations for Process containing Calciner and SO₂

| RBLC ID | Facility | State | Update | Process Type | Process Type |
|---------|--|-------|------------|--|--------------|
| IA-0070 | Lehigh Cement Company - Mason City Plant | IA | 12/11/2003 | Kiln/Calciner/Preheater | 90.028 |
| IA-0052 | Lafarge Corporation | IA | 7/1/2002 | Cement Manufacturing Preheater/Precalciner Kiln | 90.028 |
| CO-0043 | Rio Grande Portland Cement Corporation | CO | 9/25/2000 | Preheater/Precalciner, Kiln | 90.028 |
| MD-0027 | Lehigh Portland Cement Company | MD | 6/8/2000 | Cement Manufacturing, Preheater/Precalciner Kiln | 90.028 |
| IL-0057 | Illinois Cement Company | IL | 6/12/1998 | Kiln, Cement, Preheater-Precalciner | 90.028 |

RBLC Search Conducted: All RBLC Determinations for Process containing Activation Furnace and SO₂

| RBLC ID | Facility | State | Update | Process Type | Process Type |
|---------|--|-------|------------|-----------------------------|--------------|
| AL-0205 | Anniston Chemical Agent Disposal Facility Field Office | AL | 12/28/2004 | Deactivation Furnace System | 21.2 |
| AL-0178 | Anniston Army Depot – Chemical Weapons Incinerator | AL | 1/9/2003 | Deactivation Furnace | 21.2 |
| TX-0361 | Equistar Chemicals, | TX | 1/5/2005 | Cat. Reactivation Furnace | 19.6 |

The next step consists of searching the EPA RBLC database for similar emissions units, as above. The discussion parallels that for NO_x above, as does the following discussion of large boilers, industrial boilers, and commercial/institutional boilers.

It was assumed that sulfur dioxide controls on coal fired boilers and furnaces could potentially transfer to NORIT's processes. Of the results returned for process type 11.110, 'Coal Fired Large Utility Boilers / Furnaces' (capacity greater than 250 million British thermal unit per hour (MMBtu/hr)), 37 coal fired boilers were identified in the RBLC database. The sulfur oxides controls and/or control technologies that were determined to be BACT-PSD at the time of permitting action included ten boilers with limestone injection / dry flue gas desulfurization; two boilers with a combined emission limit, limestone injection, and CEMS; three boilers with a wet scrubber; three boilers with a limit on the sulfur content of the coal; one boiler with a limit on the sulfur content of the coal and limestone injection; three boilers with limestone injection with fly ash reinjection; three boilers with the option of limestone injection followed by a spray dryer; one boiler with dry flue gas desulfurization and CEMs; two boilers with Flue Gas Desulfurization system with a fabric filter; and one boiler with spray dryer absorber. The remaining eight boilers under the large utility boilers process type were not specifically noted as having sulfur dioxide control required as BACT-PSD. These determinations were marked "N/A", "NSPS", or "Other" based on case-by-case determination. The controls and/or control technologies on these boilers included one boiler with limestone injection and fuel sulfur limits, one boiler with fly ash reinjection; two boilers with dry flue gas desulfurization system (Wet

scrubbing), two boilers with good combustion practices by limiting the sulfur content in the fuel; and two boilers with a limestone fluidized bed.

The search performed on industrial sized boilers and furnaces (capacity between 100 and 250 MMBtu/hr) returned six boilers in this category. Controls included two boilers with limestone injection / flue gas desulfurization; two boilers with a wet scrubber; and two boilers with no feasible controls determined to be BACT-PSD at the time of the permitting action.

Finally, a search conducted for commercial / institutional size boilers (capacity less than 100 MMBtu/hr) found no results.

RBLC search results for the previous categories follow. These lists identify the companies and processes found. BACT requirements, if any, have been discussed in the preceding paragraphs. More details may be found in Appendix A of the permit application.

**All RBLC Determinations for Process Code 11.110
Large Coal Fired Boilers > 250 MMBTUH and SO2**

| RBLC ID | Facility | State | Update | Process Type |
|----------------|---|--------------|---------------|--|
| ND-0024 | Great River Energy Spiritwood Station | ND | 9/14/2007 | Atmospheric Circulating Fluidized Bed Boiler |
| UT-0070 | Desert Power Electric Cooperative Bonanza Power Plant Waste Coal Fired Unit | UT | 8/30/2007 | Circulating Fluidized Bed Boiler 1445 |
| IA-0091 | Iowa Power And Light Ottumwa Generating Station | IA | 2/27/2007 | Boiler #1 |
| OK-0118 | Western Farmers Electric Corporation Wygen 3 | OK | 2/9/2007 | Coal-Fired Steam Boiler (Unit 2) |
| WY-0063 | Black Hills Corporation | WY | 2/5/2007 | Boiler |
| NE-0041 | Ag Processing, Inc. Agp Soy Processing | NE | 9/11/2006 | Unit 3 Boiler |
| WV-0024 | Western Greenbrier Co- Generation | WV | 4/26/2006 | Circulating Fluidized Bed Boiler |
| CO-0055 | Lamar Utilities Board DBA Lamar Light & Power | CO | 2/3/2006 | Circulating Fluidized Bed Boiler |
| MO-0071 | Great Plains Energy Kansas City Power & Light Company | MO | 1/27/2006 | Pulverized Coal Boiler |
| MO-0071 | Great Plains Energy Kansas City Power & Light Company | MO | 1/27/2006 | Pulverized Coal Boiler Unit 2 |
| TX-0518 | Valero Refining - Valero Heavy Oil Cracker | TX | 11/16/2005 | Emissions |
| VA-0296 | Virginia Polytechnic Institute and State University | VA | 9/15/2005 | Operation Of Boiler |
| LA-0176 | Louisiana Generating, | LA | 8/22/2005 | New 675 Mw Pulverized Coal Boiler |
| PA-0249 | River Hill Power Company | PA | 7/21/2005 | Boiler |
| PA-0248 | Wellington Dev/Greene Energy Resource Recovery Project | PA | 7/8/2005 | 2 Boilers |
| ND-0021 | Montana Dakota Utilities/Westmoreland Power Gascoyne Generating Station | ND | 6/3/2005 | Boiler-Coal-Fired |
| NV-0036 | Newmont Nevada Energy Investment | NV | 5/5/2005 | Coal Boiler |
| PA-0247 | Robinson Power Company Beech Hollow Power Project | PA | 4/1/2005 | Coal-Fired |
| NE-0031 | Omaha Public Power District | NE | 3/9/2005 | Unit 2 Boiler |

| RBLC ID | Facility | State | Update | Process Type |
|---------|--|-------|------------|--|
| MO-0060 | City Utilities of Springfield - Southwest Power Station | MO | 12/15/2004 | Pulverized Coal Fired Boiler |
| NH-0013 | Public Service of New Hampshire | NH | 10/25/2004 | Boiler, Coal Fired, Unit #5 |
| WI-0228 | Wisconsin Public Service Wps - Weston Plant | WI | 10/19/2004 | Super Critical Pulverized Coal Electric Steam Boiler |
| UT-0065 | Intermountain Power Service Corporation - Power Generating Station | UT | 10/15/2004 | Pulverized Coal Fired Electric Generating Unit |
| UT-0064 | Nevco - Sevier Power Company | UT | 10/12/2004 | Boiler With Dry Lime Scrubber |
| NE-0018 | Hastings Utilities Whelan Energy Center | NE | 3/30/2004 | Boiler, Unit 2 Utility |
| WV-0023 | Longview Power | WV | 3/2/2004 | Boiler, |
| SC-0104 | Santee Cooper Cross Generating Station | SC | 2/5/2004 | Boiler No. 3 And No. 4 |
| WI-0225 | Manitowoc Public Utilities | WI | 12/3/2003 | Circulating Fluidized Bed Boiler (Electric Generation) |
| TX-0298 | Reliant Energy Inc. Wa Parish Electric Generating Station | TX | 10/15/2003 | Boilers, Units 5 & 6, Coal & Gas |
| PA-0182 | Reliant Energy Seward Power | PA | 8/26/2003 | Boiler, Circulating Fluidized Bed |
| AR-0079 | Plum Point Associates | AR | 8/20/2003 | Boiler |
| OH-231 | First Energy Toledo Edison Co. | OH | 7/31/2003 | Boiler, Coke/Coal-Fired |

**All RBLC Determinations for Process Code 12.110
Large Coal Fired Boilers <250 MMBTUH and SO₂**

| RBLC ID | Facility | State | Update | Process Type |
|---------|--|-------|-----------|-------------------------|
| ND-0020 | Red Trail Energy, LLC Richardson Plant | ND | 8/4/2004 | Boiler, Coal Fired |
| VA-0267 | VPI University Power Station | VA | 8/30/2001 | Boiler, Overfeed Stoker |

Because the results of the RBLC searches were very limited, additional permitting documentation for the VAC process and similar processes was reviewed. The documentation reviewed includes supporting permit documentation that is publicly available. The results of this review are presented in the following subsections.

Virgin Activated Carbon Manufacturing

As above in discussion about NO_x.

The permitting information gathered for the Calgon facilities indicated that carbonizers at both facilities are equipped with wet scrubbers. As an additional point of reference, NORIT also owns and operates a thermal VAC process in Marshall, Texas. Although VAC is produced by a thermal process at the Marshall Facility, the process is inherently different in that it is a direct activation process, not a re-agglomeration process. The Marshall facility is also included in this analysis. The Title V Permit for the Calgon Catlettsburg Facility represents a 75% SO₂ control efficiency for bakers (i.e., carbonizers) that are equipped with wet scrubbers. The Calgon Bay St. Louis facility Title V Permit does not explicitly list the SO₂ control efficiency. However, it is expected that the wet scrubbers at the Calgon Bay St. Louis facility would achieve control similar to that represented for the Calgon Catlettsburg facility, given discussions with controls vendors. It should be noted that the Calgon Catlettsburg Facility is located in a portion of Boyd County, Kentucky that has been designated as an SO₂ non-attainment area. The language in the Calgon Catlettsburg Facility Title V permit statement of basis¹⁵ indicates that the scrubbers were installed for the purpose of demonstrating compliance with the SO₂ National Ambient Air Quality Standards (NAAQS), not for the purposes of meeting BACT. A review of the Sulfur Dioxide Redesignation Request prepared by the Kentucky Division of Air Quality and submitted

to the U. S. EPA in November 2004, confirms that the decrease in allowable emissions resulting from the installation of wet scrubbers from Calgon's Catlettsburg facility was the primary reason Boyd County was re-designated as attainment for SO₂. This seems to indicate that the controls were installed for air quality standard attainment purposes, not for the purposes of BACT.

As an additional point of reference, the NORIT Marshall VAC process has add-on SO₂ control. However, most of the add-on SO₂ controls pre-date not only PSD / BACT regulations, but also Clean Air Act regulations. With one exception, the scrubbers were installed in the 1960s and 1978. The scrubber on the activation furnace was installed in approximately 1992. However, it was not installed as the result of PSD permitting or a BACT determination. These scrubbers provide PM control in addition to SO₂ control. The Marshall facility typically processes coal with a sulfur content of 1-1.5%.

Therefore, of the four VAC facilities discussed herein, three facilities have add-on SO₂ emission control. One of those facilities appears to have added the wet scrubbing technology for NAAQS compliance, presumably as Lowest Achievable Emission Reduction (LAER) technology under the Nonattainment New Source Review (NNSR) regulations or attainment demonstration purposes under the Kentucky State Implementation Plan (SIP). The Marshall facility utilizes wet scrubbing for add-on SO₂ controls because it is an historical technology for the facility. The use of this add-on SO₂ control does not appear to be due to PSD permitting or as the result of a BACT review. The discussions above define wet scrubbing as an available control option.

Because the RBLC searches for similar processes returned only one determination, additional permit documentation was reviewed to identify controls in place for similar processes. This review identified three additional permitting actions that are relevant to this BACT analysis. A permitting action for the Cabot Carbon Black facility in Pampa resulted in an emissions increase of 4,083 tpy of SO₂. The emissions units at this facility are not equipped with SO₂ controls. Instead, this permitting action limited sulfur content in the feedstock to 3.75%. The emissions potential for this facility is 2.5 times the proposed potential-to-emit emissions rate identified elsewhere in this Memorandum. While the results of the BACT analysis conducted for this facility are not readily available, technical staff involved in the project recall the cost of control for a scrubber was approximately \$10,000 per ton. Additionally, permits for Oxbow Carbon LLC in Port Arthur, Texas reference four sulfur limits in their feedstock. The limits are 3%, 4%, 4%, and 4.5%. This facility processes almost one million pounds of green coke a year at a sulfur content of 3 to 4.5%. In 2006, Oxbow restored the emission rates for Process Kiln 5 with a submittal of a Pollution Control Project standard permit that authorizes the emissions of this facility to exceed 19,000 tons of SO₂ per year. This emissions potential is based on a review of the Maximum Allowable Emissions Rate Table (MAERT) for Texas Commission on Environmental Quality (TCEQ) permit numbers 5421 and 45622. The processing capacity of this facility is almost two orders of magnitude greater than the Pryor Facility and the emissions potential is over 11 times the current emissions at the Pryor Facility and no add-on SO₂ controls are required. Rather, feedstock sulfur content is limited.

The review of additional permit documentation for similar processes revealed that BACT for these processes is accepting a sulfur limit in the feedstock coupled with a capacity limitation.

These facilities process significantly more raw material and have a significantly higher emissions potential than Pryor Facility and add-on SO₂ controls have not been required.

Available Control Technologies

Based on the review of BACT determinations archived in the RBLC clearinghouse as well as additional permitting documentation, the following list of available control technologies was generated. These control technologies will be reviewed in the remaining steps of the top-down BACT review.

- limestone injection / lime scrubber / dry flue gas desulfurization
- wet scrubber
- limit on feedstock sulfur content

Step 2 – Eliminate Technically Infeasible Options

While several of the available control options are technically challenging or have significant adverse economic or environmental impacts, none of them is technically infeasible. Adverse impacts are discussed in more detail below.

Step 3 – Rank Remaining Control Options Based on Effectiveness

Following is a discussion of each add-on control option, presented in order based on their efficiency from an emission control perspective: (1) wet scrubbing, (2) dry scrubbing, and (3) feedstock sulfur limitation.

Wet Scrubbing

Wet scrubbing can achieve a 75% to 90% reduction in sulfur oxides control, making wet scrubbing the most effective control technology. The efficiencies are based on an evaluation of wet scrubber control efficiencies represented in recent permit applications, literature reviews, and provided by control equipment vendors. That wet scrubbing is the most effective control is supported by the fact that the Title V permit for Calgon Catlettsburg Facility appears to indicate that wet scrubbing represents Lowest Allowable Emission Rate (LAER) technology.

For the purposes of this BACT review, two wet scrubbing configurations were evaluated. The configurations included individual scrubbers on each carbonizer stack and a second configuration to install a common scrubber to service both carbonizers. In addition, given the high wastewater treatment costs for scrubber blowdown, an innovative wet scrubbing technology known as dual alkali scrubbing was evaluated based on the same configurations above. The vendor indicated that this dual alkali system can also achieve 90% control efficiency without generating any wastewater blowdown.

Dry Scrubbing

The next most effective add-on control technology was determined to be limestone injection or dry limestone scrubbing. Based on vendor quoted efficiencies, an overall sulfur dioxide control efficiency of 50% may be expected for limestone scrubbing for the NORIT Pryor facility VAC process. This efficiency was determined by vendors based on the SO₂ concentrations in the carbonizer and furnace exhaust measured during the June 2004 NORIT Pryor VAC process stack test. The lower control efficiency for dry lime scrubbing as compared to wet scrubbing was indicated by control equipment vendors to be a function of the relatively low SO₂ concentrations in the carbonizer and furnace exhaust as compared to typical vent streams controlled by limestone injection. For the purposes of this review, dry scrubbing configurations were

evaluated that included individual scrubbers on each carbonizer stack and a second configuration to install a common scrubber to serve both carbonizers.

Feedstock Sulfur Limit

Although not an add-on control technology, limiting the coal feedstock sulfur content for VAC manufacture was evaluated as potential BACT. The feedstock characteristics for thermal VAC processes are not publicly available due to the proprietary nature of VAC manufacture. However, anecdotal information indicates that the feedstock at one of the Calgon facilities contains an average of 1.5% sulfur. Additionally, the RBLC clearinghouse contains records of BACT determinations that limited the sulfur content of the coal fired in carbon black manufacture to 3%. Finally, as a third point of reference, the current coal feedstock sulfur content for the Pryor contains an estimated average feedstock sulfur content of approximately 1%. Since the sulfur content of the feedstock currently used at the Pryor Facility appears to be the most stringent of the feedstock limits indicated for other facilities, it will be evaluated during the following steps of the BACT analysis.

Step 4 – Evaluate Most Effective Controls

According to top-down BACT protocol, the control options must be evaluated from most to least stringent control option. The most stringent control option that is not rejected is determined to be BACT. This section documents the review of the control options in the rank order determined in Step 3.

Wet Scrubbing

Wet scrubbing to reduce sulfur dioxide emissions appears to be LAER and is the most stringent control option. While the wet scrubber may achieve the highest level of control efficiency, installation of a wet scrubber at the Pryor Facility presents several challenges. Due to the locations of the two carbonizers to be controlled, either a scrubber must be installed on each carbonizer exhaust stack or a common ducting system must be constructed. The cost for the common ducting could be substantial and would require detailed engineering configuration of the site specific factors to accurately estimate costs associated with a single scrubber.

Environmental Impacts

The environmental drawbacks to wet scrubbing are the generation of wastewater in the form of scrubber blowdown and the scrubber sludge that is generated. The blowdown issue is magnified for the Pryor Facility in that they discharge their wastewater to the existing publicly owned treatment works (POTW). In the past, the Pryor Facility faced challenges related to the selenium content in their wastewater. Selenium is a known aquatic toxic and discharges of selenium from the Pryor Facility and the POTW are restricted by permit limits. The wastewater resulting from wet scrubbing would likely increase the selenium loading to the POTW. In addition to requiring re-permitting for the Pryor Facility, the additional discharges of selenium may push NORIT's POTW, the Oklahoma Ordnance Works Authority (OOWA), to their permit limit for selenium. The Pryor Facility would essentially utilize all remaining selenium capacity as a result of installing a wet scrubber. It is unlikely that NORIT could successfully re-permit the Pryor Facility and continue to discharge to OOWA without major modifications. Wet scrubbing also has several drawbacks from an emission control perspective. Wet scrubbing technology may generate additional PM emissions on the order of 1% associated with the solids created as a result of reaction between the scrubbing medium and the treated waste gas. Furthermore, the wet scrubbing technology may create particulate matter in the form of condensables with an aerodynamic diameter less than 2.5 microns (PM_{2.5}), thereby creating additional air quality

concerns given US EPA's proposed PM_{2.5} NAAQS. Finally, although wet scrubbing may be effective in reducing SO₂ emissions, an unintended effect of wet scrubbing, depending on the scrubbing medium is the potential production of sulfuric acid mist (H₂SO₄) due to the reaction of SO₂ with water.

Dual alkali scrubbing technology could be utilized to mitigate some of the negative environmental impacts of wet scrubbing. However, it too carries a negative environmental impact. A significant volume of filter cake is generated and requires on-site handling and off-site treatment and disposal.

Economic Impacts

Wet scrubbing is used as add-on SO₂ control at some of the VAC plants in the United States. However, the annualized costs associated with the wet scrubbing at the Pryor Facility appear to be prohibitive from an economic perspective. The technology is fraught with significant operating costs due to the need to dispose of the wastewater and wastewater solids generated, the cost to purchase water as the scrubbing medium, water availability, the electricity required for pumping wastewater, and general maintenance required on a wet scrubber due to a propensity to "foul". In addition, the capital costs associated with wet scrubbing are high due to the infrastructure needed for wastewater collection and treatment, the large footprint of the wet scrubbing equipment, and chemical handling facilities.

As mentioned above, the current design and configuration of the Pryor Facility cannot accommodate the scrubber effluent generated as a by-product of wet scrubbing and still meet POTW pre-treatment standards. Additional infrastructure would be needed for wastewater collection and treatment. When the cost of the infrastructure required to handle and treat the scrubber effluent is added to the cost of the scrubber, the capital investment required for the wet scrubber significantly increases. Although a detailed design was not prepared for the necessary wastewater treatment plant installations, the costs for wastewater treatment equipment are expected to be as expensive as the cost of the scrubbers themselves. One vendor that was queried provided a quoted cost for a wet scrubber for the combined case of the carbonizers at the Pryor Facility of \$370,000. This cost did not include operating costs or the cost to install a common ducting system. The annualized cost of control for a common scrubber in turn was calculated to be \$766,916, not including the cost of the common ducting. The annualized costs of control to install a scrubber on the primary and secondary carbonizers are \$440,733 and \$433,539, respectively. The resultant cost effectiveness for these two control schemes is \$3,738 per ton and \$1,230 per ton, respectively. This cost is considerably lower than what would be expected since the cost analysis was generated on caustic costs from 2006. Detailed calculations for the annualized cost and cost effectiveness are presented in Appendix B of the permit application. As previously mentioned the costs above do not take into consideration the costs for any modification that may be required if selenium levels are increased. Note that the 75% scrubber control cost is not discussed since it is insignificant. Detailed calculations for the annualized cost and cost effectiveness for the wet scrubbing technology are contained in Appendix B of the permit application.

As mentioned above, innovative scrubbing technology was considered in light of the significant challenges of handling, treating, and discharging scrubber effluent. A dual alkali scrubber was evaluated that eliminates wastewater blowdown. Instead of scrubber wastewater effluent, the unit generates a solid filter cake that must be treated and / or disposed. The dual alkali scrubber

vendor provided a cost quote of \$1,050,000 for a single dual alkali scrubber to control the combined waste stream from Pryor Facility primary and secondary carbonizers. It should be noted that this cost did not include operating costs or the cost to install a common ducting system, which would increase the capital cost and resultant annualized cost. Without the aforementioned considerations for common ducting or equipment for filter cake management, the annualized cost of control for a common dual alkali scrubber was calculated to be \$968,152, which relates to a cost effectiveness of \$2,059. The annualized costs of control to install a dual alkali scrubber on the primary and secondary carbonizers separately were calculated to be \$848,460 and \$820,618, respectively, which relates to a cost effectiveness of \$7,196 and \$2,329, respectively. Detailed calculations for the annualized cost and cost effectiveness are presented in Appendix B of the permit application.

A review of the RBLC clearinghouse indicated that cost effectiveness data is not recorded for the majority of the determinations archived in the database and none of the RBLC determinations that identified wet scrubbing as the control device included cost effectiveness data. Of the dry scrubbing / lime scrubbing RBLC entries, only seven determinations included cost effectiveness data. All seven determinations were for industrial sized coal fired boilers with capacities between 100 and 250 MMBtu/hr. The cost effectiveness ranged from \$500 per ton to \$644 per ton. These reported RBLC costs are almost an order of magnitude less than those calculated for a wet scrubber at the Pryor Facility even without consideration of wastewater modifications and additional ductwork that may be required. A summary of the RBLC determinations that contained cost effectiveness data is included in Appendix A of the permit application.

Based on review of the site-specific energy, environmental, and economic impacts, wet scrubbing is rejected as BACT for the carbonizers at the Pryor Facility.

Lime Scrubbing

The next most stringent control option is scrubbing via limestone injection. This technology is commonly used as an effective control technology in coal fired boilers. However, given the low concentrations of SO₂ in the VAC process the level of control achieved is significantly less than that would be achieved through wet scrubbing.

Environmental Impacts

Lime scrubbing generates a significant solid waste stream. Depending on which sources are controlled, the solid waste stream generation rate may range between 40 and 159 tons per year. This would result in an additional environmental impact in that the waste stream may require landfill or other disposal methods.

Economic Impacts

The limestone injection control equipment vendor provided a cost quote of \$775,000 for a single limestone injection system to control the combined waste stream from Pryor Facility primary and secondary carbonizers. It should be noted that this cost did not include operating costs or the cost to install a common ducting system which would increase the capital cost and resultant annualized cost associated with a single control system. Without the aforementioned considerations for common ducting and equipment for spent lime management, the annualized cost of control for a common limestone injection system was calculated to be \$737,348, which relates to a cost effectiveness of \$2,822. The annualized costs of control to install a limestone injection system on the primary and secondary carbonizers separately were calculated to be \$615,107 and \$624,119, respectively, which relates to a cost effectiveness of \$9,391 and \$3,188,

respectively. Detailed calculations for the annualized cost and cost effectiveness for the limestone injection control technology are contained in Appendix B of the permit application.

As previously indicated, the cost effectiveness data available in the RBLC clearinghouse reveals several determinations that included cost effectiveness data for dry scrubbing systems. The average cost effectiveness for these systems was \$500 per ton. The estimated cost presented for any of the limestone injection control scenarios above, without additional site specific considerations that would increase the capital and annualized costs, are more than an order of magnitude higher than the cost effectiveness indicated as BACT in the RBLC clearinghouse.

Based on taking into account the site-specific economic and environmental impacts, lime scrubbing is rejected as BACT for the carbonizers at the Pryor Facility, primarily as a function of the high cost of control

Limiting Sulfur Content in Raw Coal

Although an effective limit on the sulfur content in the VAC process feedstock is not an add-on control, it is a manner of reducing potential SO₂ emissions. Recent permitting determinations have defined a sulfur limitation from certain processes as BACT. This was previously discussed in the review of the carbon black industry above, where a 3% sulfur limit in carbon black feedstock was accepted as BACT as recently as December 28, 2004. Additionally, recent BACT determinations for coal fired boilers reflected in the RBLC clearinghouse indicate that limiting the sulfur content of feedstock to 1.2% was considered to BACT as recently as March 2005.

The effective emission reduction that is achieved through limiting the coal sulfur content would generally be based on the sulfur content of the previous raw material as compared to the proposed raw material. In the case of the Pryor Facility, it appears that lower sulfur coals have been in use since at least 1986, with the feedstock coal containing an average of approximately 1.0% sulfur. These sulfur levels are consistent with recent BACT determinations; this implies that the Pryor Facility VAC process already meets BACT. Based on this review, accepting a limit on the sulfur content of the coal feedstock would satisfy the BACT requirements without any additional, economic, environmental or energy constraints except to the extent that the costs that NORIT pays for their coal appears to be higher than that for the VAC industry standard coal. The 1.5% maximum sulfur content of the coal in use at the Pryor Facility is equal to the current thermal VAC industry standard and less than the sulfur content limit in carbon black manufacturing feedstock (3% sulfur). Compared to a 3% industry standard coal with a unit cost of approximately \$110 per ton, NORIT currently pays \$137 per ton for their coal feedstock. Given the previous cost information and based on an annual coal usage rate of 78,840 tons per year, this correlates to an operating cost to NORIT of \$2,128,680 per year for a cost effectiveness of approximately \$1,332 per ton of SO₂. This cost effectiveness appears to be reasonable given the fact that there are no additional environmental or energy constraints.

Step 5 – Selection of BACT

NORIT proposes an effective limit on the sulfur content of coal used as a raw material at the Pryor Facility. An effective limit on the sulfur content in the coal was selected as BACT, because both wet and dry scrubbing methods were rejected as BACT.

Wet scrubbing was rejected as BACT due to adverse environmental impacts and significant costs associated with wet scrubbing that resulted in a very high cost per unit control (or low cost

effectiveness.) Additionally, although not quantified in this analysis, wet scrubbing generates a significant wastewater stream that cannot be currently handled at the Pryor Facility. It is expected that the scrubber blowdown would have inherent chemical properties that would require the Pryor Facility to install new wastewater treatment devices, creating an additional economic burden. Finally, the environmental impacts as a result of wet scrubbing due to the generation of additional wastewater, as well as the potential collateral particulate matter emissions, eliminate wet scrubbing as BACT.

Dry scrubbing was also rejected as BACT due to adverse economic and environmental impacts. This high cost of control coupled with the additional environmental burden of solids handling resulted in eliminating dry scrubbing as BACT.

As specified in the EPA's Top-Down BACT protocol, the most stringent control option not eliminated is selected as BACT. Therefore, an effective limit on the sulfur content in the raw coal used in the manufacturing of activated carbon is selected as BACT. The proposed maximum effective limit is 1.5% sulfur in coal. This limit is lower than recent BACT determinations that have endorsed up to 3.0% sulfur limits in feedstock.

DEQ has reviewed these arguments and has some disagreement. For instance, with the exception of "Dual Alkali Scrubber on Primary Carbonizer" and "Limestone Injection of Primary Carbonizer," the cost effectiveness of each situation analyzed was within reasonable limits. Although environmental arguments were raised for several of the relatively inexpensive options, these objections were not analyzed as to economic impact and cannot be rejected out of hand. The "Limit Average Sulfur Content" option is a statement of current practice at the facility and is not truly an option. However, the Consent Order to which DEQ and NORIT have agreed requires that the "Limit Average Sulfur Content" be accepted as BACT, and so it is.

B, C, D. Air Dispersion Modeling

DISPERSION MODEL

The U.S. EPA approved AERMOD (version 07026) was used to predict the maximum ground-level off-property concentrations of modeled pollutants. A commercial graphical user interface (GUI) BEEST for Windows by Bee-Line Software, Version 9.72, released in February 2008 was used to execute the AERMOD program.

In this analysis, modeling with AERMOD was performed using the regulatory default options, which include stack heights adjusted for stack-tip downwash, buoyancy-induced dispersion, and final plume rise. Ground-level concentrations occurring during "calm" wind conditions are calculated by the model using the calm processing feature. Regulatory default values for wind profile exponents and vertical potential temperature gradients were used since no representative on-site meteorological data are available. Per U.S. EPA requirements, direction-specific building dimensions were used for both the Schulman-Scire and the Huber-Snyder downwash algorithms.

LAND USE AND TERRAIN

Land use within a 3-kilometer (km) radius of the Pryor Facility was evaluated using current USGS 7.5-minute quadrangle maps and general knowledge of the area. Rural land use clearly prevails in the area. Therefore, the default rural dispersion option was used in all air quality analyses.

The complex terrain option was used in the modeling to account for the elevation of offsite sources and to accurately predict impacts. Base elevations of the facility emission sources, buildings, and all receptors were obtained from the Digital Elevation Models (DEM) files. Each DEM dataset consists of a sampled array of elevations for ground positions that are normally spaced at regular intervals. Each of the DEMs used in the modeling setup provides coverage in 7.5- by 7.5-minute blocks. 7.5-minute DEM's are also referred to as "30-meter" (because of 30-meter data spacing) or 1:24,000 scale DEM data.

Level 2 7.5-minute Quad (Quadrangle) DEM were obtained to cover a 50-km distance in each direction from the center of the facility. These DEM data coordinates were all converted to NAD83. Beyond the 50-km radius, 1-degree DEM data was used to evaluate elevations for off-site sources. These DEMs are also referred as "100-meter" (because of 100 meter data spacing) or 1:250,000 scale DEM data.

The terrain elevations were imported into the AERMOD input file using the BEEST for Windows GUI that utilizes EPA's AERMAP (version 06341) program. The elevations (and hill heights for the receptors) were calculated for each model object using AERMAP and the linear interpolation option.

BUILDING WAKE EFFECTS (DOWNWASH)

Direction-specific building dimensions and the dominant downwash structure parameters used as input to the AERMOD model were determined using the Good Engineering Practice/Building Profile Input Program for PRIME (GEP/BPIPPRM) version 04274, and the BEEST for Windows GUI. BPIPPRM is designed to incorporate the concepts and procedures expressed in the GEP Technical Support document, the Building Downwash Guidance document, and other related documents.

Data input for each structure at the Pryor facility was used by the BPIPPRM program to calculate the direction-specific downwash parameters. BPIPPRM generates the height and width downwash parameters for thirty-six compass directions for each structure with reference to each point source of emissions. BPIPPRM also takes into account the difference in the base elevation of the point source and the structure to determine the good engineering practice (GEP) stack height or the height at which the stack will not be affected by downwash from the structure.

The output from BPIPPRM contains a summary of the dominant structures for each emission unit (considering all wind directions) and the actual building heights, projected widths, and three additional parameters for 36 wind directions. This information was then incorporated into the data files for the AERMOD model using the BEEST for Windows GUI.

METEOROLOGICAL DATA

The AERMOD model runs were conducted using five years (2001-2005) of meteorological data compiled from surface data from the Tulsa International Airport (NWS Station No. 13968), upper air data from the Springfield, Missouri station (NWS Station No. 13995), and Oklahoma Mesonet data from Pryor used as on-site data. Oklahoma Mesonet data provided courtesy of the Oklahoma Mesonet, a cooperative venture between Oklahoma State University and The University of Oklahoma and supported by the taxpayers of Oklahoma. All processed and raw data files were provided by the AQD. Default settings were used in the AERMET (version 06341) preprocessor. The profile base elevation for the Tulsa International Airport station (Station No. 13968) of 198.1 meters above sea level was used in the AERMOD setup. NWS data was substituted for missing on-site data. A set of surface characteristics was generated using AERSURFACE (version 08009) for the Oklahoma Mesonet Pryor site.

Surface Characteristics for Oklahoma Mesonet Pryor Site

| | Winter | Spring | Summer | Fall |
|--------------------------|--------|--------|--------|-------|
| Albedo | 0.18 | 0.14 | 0.19 | 0.19 |
| Bowen Ratio (Avg) | 0.70 | 0.32 | 0.47 | 0.70 |
| Bowen Ratio (Dry) | 1.92 | 1.02 | 1.35 | 1.92 |
| Surface Roughness | 0.021 | 0.031 | 0.159 | 0.159 |

FACILITY

The equipment affected by this project is located at the existing Pryor Facility near Pryor, Oklahoma. In all modeling analysis input and output data files, the location of emission sources, structures, and receptors was represented in the Universal Transverse Mercator (UTM) coordinate system. All UTM coordinates used in the modeling were based on the North American Datum (NAD) 83. All emission units, buildings, structures, and property boundary locations were digitized from plot plans and/or measured on-site by NORIT personnel using advanced Global Positioning System (GPS) devices and converted to equivalent UTM coordinates. The Pryor Facility is located in Mayes County, Oklahoma. Mayes County is an attainment area for all criteria pollutants and is a Class II PSD area. The Pryor Facility is located approximately 170 kilometers (km) from the nearest Class I area.

RECEPTOR GRIDS

All receptor coordinates have a datum of NAD83. The receptor elevations for all grids were evaluated using the BEEST for Windows GUI utilizing the EPA AERMAP program, which process the DEM files covering the areas of concern. An interpolation method was utilized for the elevation calculations.

MODELING EMISSION INVENTORY

Historical and current hourly and annual emissions of each affected criteria pollutant associated with all sources at Pryor Facility, including a separate evaluation of sources affected by the carbonizer project were evaluated and quantified by the applicant. Although all of the emissions would not occur simultaneously at the maximum potential rate, all sources were included in the modeling analyses at the maximum potential rate. Emission sources included in the modeling input files were specific to each type of modeling (i.e., PSD Preliminary Impact; Full Impact; and Increment, as applicable). The source selection is addressed in each of the applicable

subsections, which provide a brief description of the modeling setup for the specific types of emission sources.

SPECIFIC MODELING ISSUES

SO₂ Review

On June 2, 2010, the EPA promulgated a new 1- hour SO₂ NAAQS of 75 ppb, which became effective on August 23, 2010. In the same notice, EPA also revoked the existing 24-hour and annual primary SO₂ standards. However, the 3-hour standard and the 24-hour and annual increments for SO₂ remain in effect. Therefore, the AQD requested that the applicant model compliance with the new standard in addition to the previous modeling that was submitted.

Based on the results of the modeling that the applicant conducted, it was been determined that the following (or equivalent) changes to the facility sources had to be made in order to meet the new standards.

1. Consolidate the emissions from the Primary Carbonizer Boiler, Secondary Carbonizer Boiler, Activator Boiler and Main Activator Stack, and route them to a single consolidated stack located approximately 60 feet to the north of the existing main activator stack.
2. Reduce the overall allowable SO₂ emissions from the four emission sources listed above by approximately 25%.

The submitted modeling demonstrated that the proposed stack configuration and emission rate would ensure compliance for the Pryor Facility with the new NAAQS. However, NORIT wanted to reserve the right to revise the emission rates and stack configurations in the near future and to achieve the goals of protecting NAAQS by means other than those represented in their application (e.g., reduce emission rates, additionally modify the stack parameters or move the stack to a different location). A demonstration of equivalency of the air impacts will be achieved through additional modeling.

NO₂ Review

On February 9, 2010, the EPA promulgated a new 1- hour NO₂ NAAQS of 100 ppb which became effective on April 12, 2010. In the same notice, EPA revoked the existing annual NO₂ standard. However, the annual increment for NO₂ remains in effect. Therefore, the AQD requested that the applicant model compliance with the new standard in addition to the previous modeling that was submitted.

The submitted modeling demonstrated that the proposed stack configuration and emission rate would comply with the new NAAQS. However, NORIT wanted to reserve the right to revise the emission rates and stack configurations in the near future and to achieve the goals of protecting NAAQS by means other than those represented in their application (e.g., reduce emission rates, additionally modify the stack parameters or move the stack to a different location). A demonstration of equivalency of the air impacts will be achieved through additional modeling.

PM₁₀/PM_{2.5} Review

On July 18, 1997, EPA revised the NAAQS for PM to add new annual and 24-hour standards for fine particles using PM_{2.5} as the indicator. EPA revised the 24-hour NAAQS for PM_{2.5} on September 21, 2006, reducing the standard from 65 µg/m³ to 35 µg/m³. EPA also retained the previous 1997 annual standard for PM_{2.5} and the 24-hour standard for PM₁₀, while revoking the annual standard for PM₁₀. Citing technical difficulties with respect to PM_{2.5} monitoring, emission estimation, and modeling, EPA established a policy, known as the PM₁₀ surrogate policy, on October 23, 1997. The policy allowed permit applicants to use compliance with the applicable PM₁₀ requirements as a surrogate approach for meeting PM_{2.5} requirements until the issues were resolved. On May 16, 2008, EPA promulgated final rules governing the implementation of the PM_{2.5} program, which included a “grandfathering provision” allowing applicants with complete applications submitted as of July 15, 2008 to continue to use the PM₁₀ surrogate policy. However, the policy was stayed on June 1, 2009, and the stay was extended on June 22, 2010. On February 11, 2010, EPA published a proposal to repeal the grandfathering provision in which the EPA extended the PM₁₀ surrogate policy for SIP-approved states until May 2011 or until revised state implementation plans (SIPs) were approved by EPA, whichever was sooner. On March 23, 2010, in response to the proposed repeal, EPA issued a letter “Modeling Procedures for Demonstrating Compliance with the PM_{2.5} NAAQS” that stated states “may still rely upon the PM₁₀ surrogate policy as long as (1) the appropriateness of the PM₁₀-based assessment for determining PM_{2.5} compliance has been adequately demonstrated based on the specifics of the project; and (2) the applicant can show that a PM_{2.5} analysis is not technically feasible.”

The application for this historical PSD permit was submitted on December 5, 2007 which was prior to the final rule governing implementation of the PM_{2.5} NSR requirements. Therefore, the application was grandfathered from the requirement to perform PM_{2.5} modeling and the use of PM₁₀ as a surrogate for PM_{2.5} would be acceptable if the two requirements stated in the letter from the EPA was met. The permittee indicated that regulating PM₁₀ for this project would control PM_{2.5} because PM_{2.5} is a portion of PM₁₀ emissions and that there was a strong statistical relationship between PM₁₀ and PM_{2.5} emissions. The permittee also indicated that the degree of control of PM_{2.5} emissions by the control technology selected in the PM₁₀ BACT analysis was as effective as the technology that would have been selected if a BACT analysis specific to PM_{2.5} emissions had been conducted. The permittee stated that PM_{2.5} modeling was technically infeasible because PM_{2.5} emissions from nearby sources was unknown. In May 2009 NORIT conducted PM stack tests on major stacks at the Pryor Facility. The May 2009 stack tests contained 11 cumulative particle size analysis profiles for two emission sources. The cumulative PM_{2.5} volume percent ranged from 0.82% to 14.02%. As a conservatively high estimate, 14.02% is used to represent the ratio. Thus, the highest PM_{2.5} concentrations are assumed to be the product of 14.02% and the respective PM₁₀ concentrations. AQD used the stack test data along with updated stack information to conduct preliminary impact modeling for PM₁₀ and thus PM_{2.5}.

PRELIMINARY IMPACT MODELING (PIM)

Preliminary impact modeling was conducted to determine the Radius of Impact (ROI) and establish the corresponding minimal Area of Significant Impact (AOI), i.e., the area in which receptors must be located and the distance for which nearby sources must be considered for

inclusion in the modeling database to evaluate compliance with NAAQS and PSD Increment standards.

The PIM analyses were completed for SO₂, NO₂, and PM₁₀. To determine whether Full Impact Modeling (FIM), PSD Increment modeling, and pre-construction and/or post construction ambient air monitoring for each pollutant was required, modeling of emissions from the new, modified or contemporaneous sources at the facility was conducted to determine if the predicted concentrations equal or exceed the significant impact levels (SIL) for each respective pollutant and averaging period.

If a maximum predicted concentration exceeds the SIL for a respective pollutant and averaging period, an Area of Significant Impact (AOI) is defined. The AOI is a circular region centered on the modeled on-site sources with the radius extending to the farthest receptor that equals or exceeds the SIL for that pollutant and averaging period. For determination of the AOI, EPA requires modeling of “contemporaneous emissions increases and decreases” (i.e., the difference between the post-project emissions and pre-project emissions). Preliminary modeling was conducted using the net project changes originating from the affected sources. The project baseline years selected for this modeling are 1988 and 1989. The emissions changes were estimated based on the historical emission records and design of the equipment affected by the primary carbonizer project.

Nine individual emission sources at the Pryor Facility were included in the modeling analyses. All sources were classified as point sources. Tables containing the source parameters and emission rates specific for the PIM runs are contained in the submitted modeling report. All parameters used in the modeling were based on conservative assumptions. The annual emission rates correspond to 8,760 hours of operation for each source at the maximum hourly emission rate. Only one source group was created for the PIM analyses to represent the maximum off-property concentration.

The original PIM used a coarse grid with receptors spaced 1 km apart and covered a region extending 50 km from all edges of the fence line. Since the software builds a rectangular Cartesian grid, the receptors were converted into discrete receptors and all receptors beyond the 50-km radius were eliminated. For some receptors (e.g., receptors at the edge of DEM files) AERMAP was not able to calculate the elevations and terrain heights. During the pre-modeling protocol discussion, the applicant requested and received approval to remove such receptors from the grid. An additional refined grid with receptors spaced 100 meters apart and extending 500 meters from the fence line was used to ensure that no significant impact from the facility was overlooked. For later PIM the receptor grid used was the grid used for NAAQS modeling.

PIM Results

The PSD air quality analyses were conducted in conformance with federal and state requirements. A summary of the PIM results is provided below.

Summary of the PIM Results

| Pollutant | Averaging Period | SIL ($\mu\text{g}/\text{m}^3$) | Impact ($\mu\text{g}/\text{m}^3$) | ROI (km) |
|-------------------|-------------------------|--|---|-----------------|
| SO ₂ | 1-hour ¹ | 7.9 | 58.1 | 19.9 |
| SO ₂ | 3-hour ² | 25.0 | 30.3 | 19.5 |
| SO ₂ | 24-hour ³ | 5.0 | 8.9 | 7.3 |
| SO ₂ | Annual ³ | 1.0 | 0.9 | N/A |
| NO ₂ | 1-hour ⁴ | 7.5 | 24.5 | 20.0 |
| NO ₂ | Annual ³ | 1.0 | 0.8 | N/A |
| PM ₁₀ | 24-hour ² | 5.0 | 2.8 | N/A |
| PM ₁₀ | Annual ³ | 1.0 | 0.0 | N/A |
| PM _{2.5} | 24-hour ² | 1.2 | 0.4 | N/A |
| PM _{2.5} | Annual ² | 0.3 | 0.0 | N/A |

¹ - Interim SIL established by EPA in August 23, 2010 Guidance.

² - For NAAQS and Increment.

³ - For Increment only.

⁴ - Interim SIL established by EPA in June 29, 2010 Guidance.

The PIM analysis results indicate that the proposed project is significant for SO₂ for the 1-hour, 3-hour, and 24-hour averaging periods and for NO₂ for the 1-hour averaging period. Therefore, Full Impact Modeling was completed for the SO₂ 1-hour NAAQS, 3-hour NAAQS and Increment, and 24-hour Increment and for the NO₂ 1-hour NAAQS.

Comparison of the Results with the Monitoring Significance Levels (MSL)**Summary of the PIM Results**

| | Averaging | MSL | Impact |
|------------------|------------------|--|--|
| Pollutant | Period | $\mu\text{g}/\text{m}^3$ | $\mu\text{g}/\text{m}^3$ |
| SO ₂ | 24-hour | 13 | 8.9 |
| NO ₂ | Annual | 14 | 0.8 |

Since the predicted 24-hour SO₂ and annual NO₂ concentration were below the MSL the facility would not be required to do any ambient monitoring. However, representative local NO₂ and SO₂ monitoring data is available. There is a tribal monitoring station (ID: 400979014) located at Cherokee Heights Drive in Mayes County, Oklahoma which would meet the guidance provided in the U.S. EPA *Meteorological Monitoring Guidance for Regulatory Modeling Applications* (EPA-454/R- 99-005) publication and Section 8.2 (Background Concentrations) of *Appendix W to 40 CFR Part 51 - Guideline on Air Quality Models*.

Background Concentrations

Since NAAQS modeling requires background concentrations to be added to the modeled impact to account for background sources, available ambient air monitoring data for SO₂ and NO_x from monitoring Site ID 400979014 in Mayes County, OK, which is considered representative for Pryor, was reviewed.

Monitoring Data for Mayes County, Oklahoma ($\mu\text{g}/\text{m}^3$)

| Pollutant | NO₂ | SO₂ | |
|--------------------|-----------------------------------|-----------------------------------|----------------------------|
| Avg. Period | 1-hour | 1-hour | 3-hour |
| Value | 98th Percentile | 99th Percentile | 2nd High |
| 2007-9 | 20.8 | 83.9 | 102.2 |

As stated in the March 1, 2011, memorandum “Additional Guidance on Application of Appendix W Modeling Guidance of the 1-hour NO₂ National Ambient Air Quality Standard”:

“if the background source inventory included in the modeling is complete enough and background levels due to mobile sources and/or minor sources that are not explicitly modeled is expected to be small, an analysis based solely on modeled emissions and no monitored background might be considered adequate for purposes of the cumulative impact assessment.”

The source inventory for SO₂ includes all SO₂ sources in and around the facility except for mobile sources and distant minor/major sources and the expected impact from those sources is expected to be less than the SIL. Also, all of the modeled sources were modeled at their potential to emit. Therefore, in an effort to reduce “the potential for double-counting of modeled and monitored contributions” and to accurately determine the impacts from the modeled sources, no background concentrations were added to the modeled concentrations to determine compliance with the SO₂ NAAQS.

FULL IMPACT MODELING (FIM) - NAAQS

Full Impact Modeling (FIM) was conducted for the pollutants and averaging periods with impacts larger than the respective SIL, based on the PIM results. All on-site sources that generate emissions of concern were included in the modeling. The affected sources were modeled with the same parameters and emissions used in the PIM modeling. The four sources that were or will be shut down after the completion of the carbonizer project were modeled with zero emissions for all pollutants.

The stack parameters and emission rates for the off-site emission sources for SO₂ and NO_x were prepared and provided by the AQD, Oklahoma Department of Environmental Quality (ODEQ). The maximum potential emissions for each source were provided in pounds per hour. Source data were provided for all sources located within 100 kilometers (km) from the center point of the facility for SO₂ and within 70 km for NO₂. The number of sources modeled was reduced by the ODEQ using the “10-D Rule” as specified in Section 2.3.4 of the Oklahoma *Air Dispersion Modeling Guidance (ADMG)*. Since only the total NO_x emissions were included, the NO_x emissions rates were adjusted using the Ambient Ratio Method scalar (conversion factor) of 0.75. All stack heights in the database were considered Good Engineering Practice (GEP) heights.

The applicant also requested source data from the Kansas, Missouri, and Arkansas environmental protection agencies for SO₂ emissions. NO_x source data was not requested because the original ROI for these pollutants determined during the PIM was less than 2 km and the distance from the facility to each of the states exceeds 70 km. Information regarding SO₂ sources with the annual

emissions exceeding the 10-D value was requested from each state. Each of the three states identified and provided only one source meeting this criterion. The Arkansas source was included in the modeling and the PTE value was used in the modeling. The source in Kansas has annual emissions below the 10-D value; however, the maximum hourly emissions were high. To reduce the number of modeling runs, both short-term and annual concentrations from this source were predicted using the short-term emission rate; thus the annual predictions are extremely conservative for that source. The SO₂ emission source identified in Missouri was located more than 130 km from Pryor, OK. For this reason and based on additional discussions with ODEQ personnel, the Missouri source was not included in the modeling.

Three source groups were created for the FIM runs. Group “ALL” included all on-site and off-site sources. Groups “ONSITE” and “OFFSITE” were created to represent on-site only and off-site only sources respectively, to independently estimate the maximum concentration for each group for additional PSD analyses.

NAAQS Modeling Receptors

The same receptor grids were established for the NAAQS and Increment modeling runs and used to estimate the appropriate impacts for each applicable pollutant and averaging period. Ground-level concentrations were predicted using receptor grids with different receptor spacing consistent with Section 2.3.7 of the ODEQ’s AQMG, December 2006 edition and additional guidance provided by AQD during discussion of the pre-modeling protocol. The following grids were established for the NAAQS and Increment modeling.

- 1) A fenceline grid at 100-meter intervals along the fence line.
- 2) A fine small grid of receptors spaced 100-meters apart and extending at least 2 km from the fence line.
- 3) A fine medium grid of receptors spaced 250-meters apart and extending at least 2 km from the fine grid.
- 4) A coarse medium grid of receptors spaced 500-meters apart and extending at least 2 km from the fine medium grid.
- 5) A large grid of receptors spaced 1-km apart and extending out to 20 km from the boundaries of the facility.

NAAQS FIM Results

The NAAQS analyses were conducted for the SO₂ 1-hour and 3-hour averaging periods and for the NO₂ 1-hour averaging period. A summary of the FIM results is provided below.

Summary of the NAAQS FIM Analyses, in Units of $\mu\text{g}/\text{m}^3$

| Pollutant | Averaging Period | NAAQS | Impact | Background | Total |
|-----------------|------------------|--------------------------|--------------------------|--------------------------|--------------------------|
| | | $\mu\text{g}/\text{m}^3$ | $\mu\text{g}/\text{m}^3$ | $\mu\text{g}/\text{m}^3$ | $\mu\text{g}/\text{m}^3$ |
| SO ₂ | 1-hour | 196.4 | 602.5 | ---- | 602.5 |
| SO ₂ | 3-hour | 1,300 | 1,054 | 102 | 1,156 |
| NO ₂ | 1-hour | 188.0 | 160.0 | 20.8 | 180.8 |

The model runs for SO₂ and NO₂ were completed for each of the five years of meteorological data. The Highest 2nd Highest (H2H) results were used to determine compliance with the 3-hour SO₂ NAAQS and the highest fourth highest and highest eighth highest were used for the SO₂ and NO₂ 1-hour NAAQS, respectively.

The modeling groups included Source Groups “ALL,” “ONSITE,” and “OFFSITE,” as discussed previously. Additional files were created to review the new 1-hour SO₂ NAAQS. The files were used to identify all receptors where the model predictions exceeded the NAAQS and to establish whether the contribution from the project modification exceeded the SIL at each receptor and time where the overall model predictions exceeded the NAAQS.

Cause or Contribute Review

The modeling results show concentrations that exceed the NAAQS for the new 1-hour SO₂ NAAQS. U.S. EPA’s New Source Review Workshop Manual (NSRWM) *Prevention of Significant Deterioration and Nonattainment Area Permitting* describing PSD modeling requirements, specifies that “when a violation of any NAAQS or increment is predicted at one or more receptors in the impact area, the applicant can determine whether the net emissions increase from the proposed source will result in a significant ambient impact at the point (receptor) of each predicted violation, and at the time the violation is predicted to occur. The source will not be considered to cause or contribute to the violation if its own impact is not significant at any violating receptor at the time of each predicted violation.” Based on review of the modeling, the facility does not have a significant impact at any of the receptors where a violation of the NAAQS is predicted to occur and therefore does not cause or contribute to the predicted exceedances of the NAAQS.

FIM - INCREMENT

Increment FIM was conducted for the SO₂ 3-hour and 24-hour Increment based on the PIM results. The facility sources were modeled with the parameters and emission rates specified in Section 4.2 of the Oklahoma *ADMG*. All emission sources at the facility were constructed after the baseline date for SO₂ (January 6, 1975) and therefore consumed increment. The on-site source parameters and emission rates were the same as those used in the FIM runs.

The list of SO₂ emission sources within 100 km of the Pryor Facility received from the ODEQ was reduced to include only the increment consuming sources built after the PSD baseline date. Upon completion of the preliminary runs, the applicant requested the actual increment consuming emission rates (for SO₂) for all sources located within 10 km of the facility. The referenced facilities were limited to GAP Roofing, Solae, and the Grand River Dam Authority. For all other facilities, the PTE values were used and modeled impacts for those sources are considered conservative.

The two emission sources located in Kansas and Arkansas were also included in the Increment modeling. Actual hourly SO₂ emissions were provided by the state of Arkansas. The state of Kansas did not provide actual hourly SO₂ emissions. Therefore, PTE values for the Kansas source were used in the Increment modeling.

Increment FIM Results

Increment modeling was conducted for the SO₂ 3-hour and 24-hour averaging periods. A summary of the FIM results is provided below.

Summary of the Increment FIM Analyses, in Units of µg/m³

| | Averaging | Increment | Impacts |
|------------------|------------------|-------------------------|-------------------------|
| Pollutant | Period | µg/m³ | µg/m³ |
| SO ₂ | 3-hour | 512 | 375 |
| SO ₂ | 24-hour | 91 | 87 |

The modeling results show that the modeled impacts do not exceed the PSD Increments.

E. Evaluation of source-related impacts on growth, soils, vegetation, and visibility.***Growth Analysis***

Per U.S. EPA Guidelines, a growth analysis is required only “if the project would result in a significant shift of population and associated activity into an area - that is, a population increase on the order of thousands of people.” A temporary increase in the population of the immediate area may have occurred during the construction period of the Carbonizer. However, the project did not result in a temporary or permanent significant population shift or increase. The number of net new jobs in the community was very small. Therefore, the applicant did not do a growth analysis.

Soils and Vegetation Analysis

The Carbonizer project does not result in any off-property concentrations of criteria pollutants in excess of NAAQS or PSD increment standards. The project will result in relatively small ambient air concentrations for SO₂ and NO_x from the on-site sources compared to off-site sources, as predicted by the model for source groups “ONSITE” and OFFSITE”. It has therefore been determined that additional analyses are not required.

Visibility Analysis

Visibility analyses evaluate impacts of the proposed projects on any Class II areas within the AOI and on any Class I areas within 100 km of the proposed site. No such areas have been established within the specified distances from the Pryor Facility. All sources affected by the project will comply with applicable visibility and opacity requirements in Oklahoma regulations. Therefore, additional modeling for visibility impairment analysis is not required.

F. Evaluation of Class I Area Impacts

A Class I PSD Area is defined as one of the following.

- International park
- A national wilderness area greater than 5,000 acres
- A national memorial park greater than 5,000 acres
- A national park greater than 6,000 acres

The State of Oklahoma contains one PSD Class I Area, the Wichita Mountains Wildlife Refuge. A map of the PSD Class I areas nearest to Pryor, OK is available in the permit application. The closest Class I area is the Upper Buffalo Wilderness Area, located in Arkansas, approximately

175 kilometers (109 miles) to the east-southeast from the Pryor Facility. Per ODEQ guidance, Class I visibility and increment analyses must be conducted if the sum of the PM₁₀, SO₂, and NO_x emission increases in tons per year (tpy) exceed 10D, where D is the distance in kilometers from the source. The combined PM₁₀, SO₂, and NO_x project emission increases for all Pryor sources are expected to be less than 520 tpy. Therefore, no PSD Class I impact analysis was performed.

A Class I area impact analysis consists of two parts:

1. PSD Class I Increment Analysis. Increment is the maximum increase in ambient pollutant concentrations allowed over baseline concentrations. SO₂, NO₂, and PM₁₀ were the pollutants analyzed.
2. AQRV Analysis. AQRVs are special attributes of a Class I area that deterioration of air quality may adversely affect. These attributes often include flora and fauna, water, visibility, cultural/archaeological sites, and natural fragrances. Not all attributes are present at all Class I areas.

Class I area impacts were determined using the AERMOD model. The nearest Class I area is 175 km distant from the Mid America facility. The distance to the extent of significant impacts was less than this distance.

| Pollutant | Averaging Period | SIL, ug/m ³ | Impacts, ug/m ³ | Distance, km |
|------------------|------------------|------------------------|----------------------------|--------------|
| NO _x | Annual | 0.1 | 0.035 | 11 |
| PM ₁₀ | 24-hour | 0.3 | 0.2 | 11 |
| | Annual | 0.2 | 0.02 | 11 |

SECTION VI. GREENHOUSE GAS EMISSIONS

Greenhouse gas (GHG) became a regulated pollutant on January 2, 2011. The facility has conducted an evaluation to demonstrate that the addition of the primary carbonizer project did not result in a net emissions increase in excess of 75,000 TPY of carbon dioxide equivalents (CO₂e). Pre-project average annual actual emissions of CO₂e were calculated for the 1986-1987 period. All pre-project coal use was 100% sub bituminous. Knowing the actual amounts of coal and pitch inputs and the carbon content of each allows the calculation of actual carbon fed to the process. Further, knowing the product yield and the average amount of fixed carbon in the product yields the amount of carbon exiting the process. A material balance approach indicates that all remaining carbon is emitted. Ignoring incomplete combustion, stoichiometry reveals total carbon dioxide emissions. The following table summarizes the assumptions and the results.

TONS, except as noted

| Parameter Measured | Subbituminous Coal | Pitch | Total |
|---------------------------|---------------------------|--------------|--------------|
| Raw Material Input | 37,995 | 1,915 | 29,910 |
| Average Carbon Content | 50.88% | 60.4% | |
| Carbon Input | 19,332 | 1,157 | 20,489 |
| Product Yield | | | 9,897 |
| Product Carbon Ratio | | | 92% |
| Carbon Output | | | 9,105 |
| Carbon Lost (Emitted) | | | 11,383 |
| CO ₂ Emissions | | | 41,738 |

In addition to the straightforward calculation of combustion emissions of CO₂, calculation of emissions of other pollutants with CO₂-equivalents was performed. Emissions of N₂O and CH₄ were calculated using factors for overfeed stokers from Table 1.1-19 of AP-42 (9/98) and CO₂e conversion factors from *PSD and Title V Permitting Guidance For Greenhouse Gases*, EPA, November 10, 2010. Note that the AP-42 factors are based on coal combusted and not on only the carbon content of the coal. This figure is based on overall yield and is averaged across both coal and pitch. Although the facility treated each input individually, the following table reflects the totals.

| Parameter | N₂O | CH₄ |
|-----------------------------|-----------------------|-----------------------|
| Coal & Pitch Combusted | 30,013 TPY | 30,013 TPY |
| Emission Factor | 0.04 lb/ton | 0.06 lb/ton |
| Emissions | 0.60 TPY | 0.90 TPY |
| Conversion Factor | 310 | 21 |
| CO ₂ e Emissions | 186 TPY | 18.9 TPY |

Thus, the total of all pre-project CO₂e emissions is 41,943 TPY.

Post-project potential to emit (PTE) CO₂e emissions are based on the permitted raw material feed rate of 18,000 lbs/hr. The method and factors used follow those used for the pre-project emissions. Because post-project coal use included bituminous and sub bituminous coal, an analysis of all coal has to be based on the average mix of coals used. Complicating this calculation is the fact that four bituminous coals have been used, each with slightly different characteristics. Figures from 2009 were used to establish some ratios and the results were applied to rated capacity of 9 TPH or 78,840 TPY of input. The first table following mimics the first table used in calculating pre-project emissions.

TONS, except as noted

| Parameter | Bit 1 | Bit 2 | Bit 3 | Bit 4 | Subbit | Pitch | Total |
|---------------------------|--------------|--------------|--------------|--------------|---------------|--------------|--------------|
| Coal Input | 509 | 6,514 | 14,799 | 18,811 | 6,194 | 3,335 | 50,161 |
| Carbon % | 55.95 | 50.32 | 62.05 | 62.30 | 50.88% | 60.4% | |
| Carbon Input | 284.5 | 3,278 | 9,183 | 11,719 | 3,152 | 2,014 | 29,630 |
| Product | | | | | | | 15,117 |
| Product Carbon | | | | | | | 92% |
| Carbon Output | | | | | | | 13,908 |
| Carbon Emitted | | | | | | | 15,722 |
| CO ₂ Emissions | | | | | | | 57,649 |

The next step calculates CO₂ equivalents in the same manner as was done for pre-project emissions, using the same factors.

| Parameter | N₂O | CH₄ |
|-----------------------------|-----------------------|-----------------------|
| Coal & Pitch Combusted | 55,080 TPY | 55,080 TPY |
| Emission Factor | 0.04 lb/ton | 0.06 lb/ton |
| Emissions | 1.1 TPY | 1.7 TPY |
| Conversion Factor | 310 | 21 |
| CO ₂ e Emissions | 342 TPY | 34.7 TPY |

Total CO₂e emissions from the two preceding tables are based on 2009 actual production data. Because the exact mix of coals to be processed after the project was complete could not have been forecast with any accuracy at the time, this actual mix provides a good basis for further analysis. Values calculated here are proportioned up to match the 9 TPH capacity of the post-project facility. Thus, $(57,649 + 342 + 34.7) \times (78,840 \div 55,080) = 83,056$ TPY of CO₂e.

Finally, emissions from natural gas combustion in the primary carbonizer and afterburner are based on maximum burner capacity, which is 105.1 MMCF/yr for the primary and 70.1 MMCF/yr for the afterburner, or 175.2 MMCF/yr total. Emission factors are taken from Table 1.4-2 of AP-42 (7/98) and the CO₂e conversion are as stated previously.

| Pollutant | Emission Factor Lb/MMCF | Emissions TPY | CO₂e Factor | CO₂e Emissions TPY |
|------------------|------------------------------------|--------------------------|-----------------------------------|--|
| CO ₂ | 120,000 | 10,512 | 1 | 10,512 |
| N ₂ O | 2.2 | 0.19 | 310 | 59.7 |
| CH ₄ | 2.3 | 0.20 | 21 | 4.23 |
| Total | | | | 10,576 |

Total post-project CO₂e emissions are 83,056 plus 10,576 = 93,632 TPY. Thus, the net emission increase is 93,632 minus 41,943 equals 51,689 TPY, well below the 75,000 TPY threshold requiring further analysis of CO₂e emissions.

SECTION VII. OKLAHOMA AIR POLLUTION CONTROL RULES

OAC 252:100-1 (General Provisions) [Applicable]

Subchapter 1 includes definitions but there are no regulatory requirements.

OAC 252:100-2 (Incorporation by Reference) [Applicable]

This subchapter incorporates by reference applicable provisions of Title 40 of the Code of Federal Regulations listed in OAC 252:100, Appendix Q. These requirements are addressed in the “Federal Regulations” section.

OAC 252:100-3 (Air Quality Standards and Increments) [Applicable]

Subchapter 3 enumerates the primary and secondary ambient air quality standards and the significant deterioration increments. At this time, all of Oklahoma is in “attainment” of these standards.

OAC 252:100-5 (Registration, Emissions Inventory and Annual Operating Fees) [Applicable]

Subchapter 5 requires sources of air contaminants to register with Air Quality, file emission inventories annually, and pay annual operating fees based upon total annual emissions of regulated pollutants. Emission inventories were submitted and fees paid for previous years as required.

OAC 252:100-8 (Permits for Part 70 Sources) [Applicable]

Part 5 includes the general administrative requirements for Part 70 permits. Any planned changes in the operation of the facility which result in emissions not authorized in the permit and which exceed the “Insignificant Activities” or “Trivial Activities” thresholds require prior notification to AQD and may require a permit modification. Insignificant activities mean individual emission units that either are on the list in Appendix I (OAC 252:100) or whose actual calendar year emissions do not exceed the following limits.

- 5 TPY of any one criteria pollutant
- 2 TPY of any one hazardous air pollutant (HAP) or 5 TPY of multiple HAPs or 20% of any threshold less than 10 TPY for a HAP that the EPA may establish by rule

Emissions limitations have been established based on information from stack testing, previous operating permits, and the permit application.

OAC 252:100-9 (Excess Emissions Reporting Requirements) [Applicable]

Except as provided in OAC 252:100-9-7(a)(1), the owner or operator of a source of excess emissions shall notify the Director as soon as possible but no later than 4:30 p.m. the following working day of the first occurrence of excess emissions in each excess emission event. No later than thirty (30) calendar days after the start of any excess emission event, the owner or operator of an air contaminant source from which excess emissions have occurred shall submit a report for each excess emission event describing the extent of the event and the actions taken by the owner or operator of the facility in response to this event. Request for affirmative defense, as described in OAC 252:100-9-8, shall be included in the excess emission event report. Additional

reporting may be required in the case of ongoing emission events and in the case of excess emissions reporting required by 40 CFR Parts 60, 61, or 63.

OAC 252:100-13 (Prohibition of Open Burning)

[Applicable]

Open burning of refuse and other combustible material is prohibited except as authorized in the specific examples and under the conditions listed in this subchapter.

OAC 252:100-19 (Particulate Matter (PM))

[Applicable]

Section 19-4 regulates emissions of PM from new and existing fuel-burning equipment, with emission limits based on maximum design heat input rating. Fuel-burning equipment is defined in OAC 252:100-19 as any internal combustion engine or gas turbine, or other combustion device used to convert the combustion of fuel into usable energy. The natural gas combusted in the following equipment is subject to the requirements of this subchapter. Several of the afterburners at this facility vent their exhaust gasses to waste heat boilers. Although afterburners are typically considered to be pollution control equipment not subject to Section 19-4, in this instance they provide usable heat to the boilers and are subject to the Appendix C limits. Table 1.4-2 of AP-42 (7/98) lists total PM emissions for natural gas-fired external combustion units to be 7.6 lbs/million scf or about 0.0076 lbs/MMBTU, which is in compliance. Table 13.5-1 of AP-42 (9/91) suggests a range of values for “soot” from industrial flares. The afterburners’ exhausts fuel waste heat boilers, and smoky exhaust would cause fouling, so it is likely that the factor of zero $\mu\text{g/L}$ is correct, but a conservatively high 20 $\mu\text{g/L}$ is used to assure compliance. Exhaust rates and heat input are assumed at their various maxima.

| Equipment | Maximum Heat Input (MMBTUH) | Emissions in lbs/MMBTU | |
|-------------------------|-----------------------------|------------------------|----------------|
| | | Appendix C Limit | Potential Rate |
| PC Heating Jacket | 8 | 0.60 | 0.008 |
| SC Heating Jacket | 10 | 0.60 | 0.008 |
| East Activation Furnace | 24 | 0.49 | 0.008 |
| West Activation Furnace | 24 | 0.49 | 0.008 |
| Acid Wash Plant Dryer | 3.3 | 0.60 | 0.008 |
| PC Afterburner | 12 | 0.60 | 0.008 |
| SC Afterburner | 18 | 0.60 | 0.008 |
| Package Boiler | 24.5 | 0.49 | 0.010* |

*Manufacturer supplied data

Section 19-12 limits particulate emissions from new and existing directly fired fuel-burning units and/or emission points in an industrial process based on process weight rate, as specified in Appendix G. As shown in the following table, all emission points are in compliance with Subchapter 19. Note that the primary and secondary carbonizing processes include two industrial processes each; namely, carbonizing and transporting. Additionally, the process weight for the carbonizing process includes raw material feed and process (reaction) air. The activation furnaces or multi-hearth furnaces (MHF) have three sections, each of which is subject to a limit. Process weight includes raw materials, reaction air, and steam. The East and West MHFs are identical in design.

| Equipment | Process Rate (TPH) | Emissions (Lbs/hr) | |
|-----------------------------|--------------------|--------------------|-------------------------|
| | | Appendix G Limit | Potential Rate |
| Area 20 crusher | 10 | 19.2 | 4.46 ¹ |
| Area 20 compactor | 10 | 19.2 | |
| Area 20 bowl mill | 10 | 19.2 | |
| Area 40 product screen | 4 | 10.4 | 0.035 ² |
| Area 40 fines screen | 2 | 6.52 | 0.017 ² |
| Regeneration product screen | 2 | 6.52 | 0.017 ² |
| Drops (9) | 20 each | 30.5 each | 0.022 ² each |
| Drops (7) | 4 each | 10.4 each | 0.004 ² each |
| Drops (2) | 2 each | 6.52 each | 0.002 ² each |
| Truck unloading | 20 | 30.5 | 0.002 ² |
| Railcar unloading (2) | 20 each | 30.5 each | 0.002 ² each |
| Front end loader (5) | 20 each | 30.5 each | 0.002 ² each |
| Front end loader (3) | N/A | N/A | |
| Thermal dryer | 10 | 19.2 | 0.05 ¹ |
| Primary (carbonizing) | 24 | 34.48 | 13.3 ³ |
| Primary (transporting) | 8.6 | 17.33 | |
| Secondary (carbonizing) | 9.75 | 18.85 | 14.0 ⁴ |
| Secondary (transporting) | 8.38 | 17.03 | |
| MHF (combined) | 57.04 | 61.58 | 24.5 ⁶ |
| MHF (combined) | 57.04 | 61.58 | 24.5 ⁶ |
| Regeneration kiln | 3.3 | 9.1 | 0.3 ⁵ |
| Acid wash plant | 1.2 | 4.6 | 3.2 ⁶ |

- 1 4/27/94 stack test
- 2 Table 11.19.2-2, AP-42 (8/04)
- 3 110% of 6/24/04 stack test
- 4 Combination of afterburner and WHB stack test results, 5/2009
- 5 9/15/95 stack test
- 6 Combination of stack and WHB stack test results, 5/5/2009

Emissions of PM from material handling and transport are very low in comparison to the allowable rate of emissions under this subchapter. No controls are required in the operating permit except for precautions taken to minimize fugitive dust.

OAC 252:100-25 (Visible Emissions and Particulates)

[Applicable]

No discharge of greater than 20% opacity is allowed except for short-term occurrences that consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity. When burning natural gas in any of the combustion devices at the facility, there is very little possibility of exceeding these standards. The thermal dryer, crusher, compactor, and coal conveying, transfer, and loading equipment are not subject to Subchapter 25 since they are subject to an opacity limitation of NSPS Subpart Y. Various operations at the facility have emissions of certain pollutants controlled by afterburners, cyclones, or baghouses. The operating permit requires operation of these devices during operation of the related

production equipment and requires appropriate maintenance of all control devices to ensure the opacity standard is met. The operating permit also requires weekly observation of the associated stacks, and opacity readings to be conducted if visible emissions are detected.

OAC 252:100-29 (Fugitive Dust)

[Applicable]

No person shall cause or permit the discharge of any visible fugitive dust emissions beyond the property line on which the emissions originate in such a manner as to damage or to interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or to interfere with the maintenance of air quality standards. The facility has numerous drop points and material processes. Normal operation of the facility with the control devices in operation should not cause a problem in this area. However, reasonable precautions to control fugitive dust emissions from the operations are stated in the operating permit.

OAC 252:100-31 (Sulfur Compounds)

[Applicable]

Part 2 limits emissions of sulfur dioxide (SO_2) from any one existing source or any one new petroleum and natural gas process source subject to OAC 252:100-31-26(a)(1). Ambient air concentrations of SO_2 at any given point shall not be greater than $1,300 \mu\text{g}/\text{m}^3$ in a 5-minute period of any hour, $1,200 \mu\text{g}/\text{m}^3$ for a 1-hour average, $650 \mu\text{g}/\text{m}^3$ for a 3-hour average, $130 \mu\text{g}/\text{m}^3$ for a 24-hour average, or $80 \mu\text{g}/\text{m}^3$ for an annual average. As discussed in Section III (Emissions) above, SO_2 emissions are difficult to quantify for individual emission points. Modeling performed for this retroactive PSD application shows worst-case aggregate concentrations of $220 \mu\text{g}/\text{m}^3$ for a 3-hour average, $86.4 \mu\text{g}/\text{m}^3$ for a 24-hour average, and $12.1 \mu\text{g}/\text{m}^3$ for an annual average. No individual source could have a concentration higher than any of these, so the 3-hour, 24-hour, and annual standards are met. No analysis of the 5-minute or 1-hour standards were offered in the modeling, and it would be inappropriate to use the scaling factors of a model such as Screen3 to evaluate them, although such an approach would yield worst-case results of $391 \mu\text{g}/\text{m}^3$ for the 5-minute average and $244 \mu\text{g}/\text{m}^3$ for the 1-hour average. Instead, the inputs used in the PSD modeling were used as inputs to Screen3 for each individual source. Noting that 1-hour impacts predicted by Screen3 may be converted to 5-minute, 3-hour, 24-hour, and annual impacts using factors of 1.6, 0.9, 0.4, and 0.08, respectively, as presented in "Screening Procedures for Estimating the Air Quality Impact from Stationary Sources", Revised (EPA-454/R-92-019), it is clear that a 1-hour result less than $325 \mu\text{g}/\text{m}^3$ will automatically satisfy all of the other averaging standards. Input data taken from the PSD model and Screen3 results are shown below. The "New Boiler" identified in the sophisticated analysis is not evaluated here because it combusts commercial quality natural gas and has negligible SO_2 emissions. The sophisticated analysis performed separate runs using Secondary Carbonizer boiler exhaust and using the same parameters at 50% bypass, resulting in identical inputs except for SO_2 , which is reduced by half in the second scenario. It is not necessary to evaluate the smaller alternate scenario. Afterburner evaluations shown at both 100% bypass and 50% bypass of the waste heat boiler are each evaluated. Note that the 1-hour value for each point is well below the threshold of $325 \mu\text{g}/\text{m}^3$, assuring compliance with the standard for all averaging periods.

| Source | Height (Feet) | Temperature (°F) | Diameter (Feet) | ACFM | SO ₂ (Lb/hr) | 1-hour µg/m ³ |
|-------------------------|------------------|---------------------|--------------------|--------|----------------------------|-----------------------------|
| Primary Carbonizer | 70.25 | 524 | 2.90 | 11,779 | 29.91 | 61 |
| Secondary Carbonizer | 140 | 547 | 2.50 | 5,677 | 89.39 | 196 |
| Activator Boiler | 120 | 700 | 3.50 | 9,785 | 63.72 | 93 |
| New Activator | 120 | 700 | 7.00 | 20,280 | 195.5 | 174 |
| Afterburner 100% Bypass | 83.67 | 1,948 | 4.33 | 8,323 | 89.39 | 148 |
| Afterburner 50% Bypass | 83.67 | 1,944 | 4.33 | 6,746 | 44.70 | 88 |

Part 5 limits sulfur dioxide emissions from new fuel-burning equipment (constructed after July 1, 1972). For gaseous fuels the limit is 0.2 lb/MMBTU heat input averaged over 3 hours. The permit requires the use of natural gas as defined in Part 72 having 20.0 grains TRS/100 scf to ensure compliance with Subchapter 31.

The activation furnaces' and carbonizer kilns' afterburner exhaust gases pass through a heat recovery, steam generating, waste heat boiler, so the afterburners are considered to be fuel-burning equipment. The afterburner's main fuel is natural gas, which can meet the emission limit above based upon AP-42 emission calculations. This view was borne out in Memoranda associated with original construction of each carbonizer. A 1978 memo claimed that the regulation did not cover volatilization of the raw coal material and a 1994 memo claimed that sulfur compounds from coal processing are not subject. Although the exact circumstances surrounding these statements are unclear, they address the case where the afterburner acts as only a control device. In the instance where the combustion products from the afterburner are used to generate steam, these statements do not apply. According to a response received from the applicant on January 19, 2010, heat from the primary carbonizer afterburner is composed of contributions from the natural gas fuel, from volatilized raw material, and from coal fines, in the respective proportions of 7.3, 4.6, and 10.6 MMBTU, for bituminous coal and in the respective proportions of 0, 20.5, and 3.1 MMBTUH for sub-bituminous coal. This requires the application of the proportional formula found in OAC 252:100-31-25(a)(4). Using the data provided, the primary carbonizer limit for SO₂ emissions is 0.671 lb/MMBTU when using bituminous coal and 0.331 lb/MMBTU when using sub-bituminous coal. These limits equate to annual emission limits of 66.1 TPY for bituminous coal and 34 TPY for sub-bituminous coal. Analysis of 2008 emission inventory records indicate that these limits are met. Sufficient data to demonstrate compliance with the appropriate limits for the other afterburners is not available. Because the data supplied in the January 19, 2010 email reflect analyses performed in 1988, a compliance plan in the Specific Conditions of the operating permit requires the collection of data to determine compliance for all afterburners.

OAC 252:100-33 (Nitrogen Oxides)

[Not Applicable]

This subchapter limits new fuel-burning equipment with rated heat input greater than or equal to 50 MMBTUH to specified emissions of NO_x in lbs per MMBTU, three-hour average. There are no equipment items that exceed the 50 MMBTUH threshold.

OAC 252:100-35 (Carbon Monoxide)

[Not Applicable]

This subchapter affects gray iron cupolas, blast furnaces, basic oxygen furnaces, petroleum catalytic cracking units, and petroleum catalytic reforming units. There are no affected sources.

OAC 252:100-37 (Volatile Organic Compounds) [Part 7 Applicable]

Part 3 requires storage tanks constructed after December 28, 1974, with a capacity of 400 gallons or more and storing a VOC with a vapor pressure greater than 1.5 psia to be equipped with a permanent submerged fill pipe or with an organic vapor recovery system. There are no tanks storing VOC that have capacity of 400 gallons or more.

Part 5 limits the organic solvent content of coating or other operations. This facility does not normally conduct coating or painting operations except for routine maintenance of the facility and equipment, which is not an affected operation.

Part 7 requires fuel-burning equipment to be operated and maintained so as to minimize emissions. Temperature and available air must be sufficient to provide essentially complete combustion.

OAC 252:100-40 (Friable Asbestos During Demolition and Renovation) [May Be Applicable]

Any projects at the facility that involve asbestos removal are affected by this subchapter. Section 40-5 describes procedures for the proper handling of asbestos.

OAC 252:100-42 (Toxic Air Contaminants (TAC)) [Applicable]

This subchapter regulates toxic air contaminants (TAC) that are emitted into the ambient air in areas of concern (AOC). Any work practice, material substitution, or control equipment required by the Department prior to June 11, 2004, to control a TAC, shall be retained, unless a modification is approved by the Director. Since no AOC has been designated there are no specific requirements for this facility at this time.

OAC 252:100-43 (Testing, Monitoring, and Recordkeeping) [Applicable]

This subchapter provides general requirements for testing, monitoring and recordkeeping and applies to any testing, monitoring or recordkeeping activity conducted at any stationary source. To determine compliance with emissions limitations or standards, the Air Quality Director may require the owner or operator of any source in the state of Oklahoma to install, maintain and operate monitoring equipment or to conduct tests, including stack tests, of the air contaminant source. All required testing must be conducted by methods approved by the Air Quality Director and under the direction of qualified personnel. A notice-of-intent to test and a testing protocol shall be submitted to Air Quality at least 30 days prior to any EPA Reference Method stack tests. Emissions and other data required to demonstrate compliance with any federal or state emission limit or standard, or any requirement set forth in a valid permit shall be recorded, maintained, and submitted as required by this subchapter, an applicable rule, or permit requirement. Data from any required testing or monitoring not conducted in accordance with the provisions of this subchapter shall be considered invalid. Nothing shall preclude the use, including the exclusive use, of any credible evidence or information relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

The following Oklahoma Air Pollution Control Rules are not applicable to this facility.

| | | |
|----------------|---------------------------------|---------------------------|
| OAC 252:100-10 | General Operating Permits | not requested |
| OAC 252:100-11 | Alternative Emissions Reduction | not requested |
| OAC 252:100-15 | Mobile Sources | not in source category |
| OAC 252:100-21 | PM from Wood Waste Burning | not type of emission unit |
| OAC 252:100-23 | Cotton Gins | not type of emission unit |
| OAC 252:100-24 | Grain Elevators | not in source category |
| OAC 252:100-39 | Nonattainment Areas | not in area category |
| OAC 252:100-47 | Municipal Solid Waste Landfills | not in source category |

SECTION VIII. FEDERAL REGULATIONS

PSD, 40 CFR Part 52

[Applicable]

Total emissions of NO_x and SO₂ are greater than the threshold of 250 TPY of any single regulated pollutant, making it a major stationary source. A retroactive PSD analysis is shown in Section V above. Any future increases of emissions must be evaluated for PSD if they exceed a significance level.

NSPS, 40 CFR Part 60

[Subparts Dc and Y Applicable]

Subpart A. This subpart contains requirements for flares used to comply with applicable subparts of parts 60 and 61 that specifically refer to this subpart. Design and monitoring requirements are included, as well as general notification and reporting requirements. The various afterburners are not referenced in any subparts covering the facilities that they serve,

Subparts D, Da, and Db (Steam Generating Units) do not apply for various reasons. The waste heat boilers are not used to generate electricity and do not combust any fuel.

Subpart Dc (Small Industrial-Commercial-Institutional Steam Generating Units) applies to steam generating units constructed, modified, or reconstructed after June 9, 1989, and with maximum design heat input capacity greater than or equal to 10 MMBTUH and less than or equal to 100 MMBTUH. It does not apply to the waste heat boilers because they do not combust any fuel. The 24.5 MMBTUH boiler of EUG 20 is an affected facility and shall comply with SO₂ and particulate standards. This boiler uses only natural gas and is not subject to standards for either pollutant. Recordkeeping of daily fuel use is required by 40 CFR 60.48(g).

Subpart K, Ka, and Kb (VOL Storage Vessels). The 320 -gallon gasoline tank is not subject to any of these subparts because it is below the threshold capacity of each of these subparts.

Subpart Y (Coal Preparation Plants) affects thermal dryers, pneumatic coal cleaning equipment, coal processing and conveying equipment (including breakers and crushers), coal storage systems, and coal transfer and loading systems at coal processing plants with a capacity of 200 TPD or more and that commenced construction, reconstruction, or modification after October 24, 1974. All affected facilities are subject to an opacity limitation of 20% and the subpart prohibits discharge from any thermal dryer of gases with 0.031 gr/DSCF of PM or more. Pneumatic cleaning is not performed at this location. Performance testing has demonstrated compliance with all of these standards.

Subpart IIII (Stationary Compression Ignition Internal Combustion Engines {CI-ICE}) affects CI-ICE constructed, modified, or reconstructed after July 11, 2005. The emergency generator

listed as an Insignificant Activity in Section IV went into operation prior to 1996, and is not an affected facility.

NESHAP, 40 CFR Part 61

[Not Applicable]

There are trace amounts of arsenic, beryllium, and mercury found in the raw coal, some of which is emitted to the atmosphere. Norit's process does not fall under the applicability determinations of Part 61 for any of these pollutants. . There are no emissions of asbestos, vinyl chloride, coke oven emissions, or radionuclides. Testing has shown the raw material to contain insufficient amounts of benzene to trigger applicability of either Subpart J or Subpart FF

Subpart J (Equipment Leaks of Benzene) concerns only process streams that contain more than 10% benzene by weight.

Subpart FF (Benzene Waste Operations) concerns operations at chemical manufacturing plants, coke by-product recovery plants, and petroleum refineries. This facility does not satisfy the definition of any of these activities, as described in 40 CFR 61.341.

NESHAP, 40 CFR Part 63

[Subpart ZZZZ Applicable]

Subpart ZZZZ, Reciprocating Internal Combustion Engines (RICE). This subpart affects RICE at major and area sources of HAP emissions. According to 40 CFR 63.6590(a)(1)(iii), the emergency generator engine listed in Insignificant Activities is an affected source, but according to §6590(b)(3), this existing emergency stationary RICE does not have to meet the requirements of Subparts ZZZZ or A, nor is initial notification required.

Subpart DDDDD (Industrial, Commercial and Institutional Boilers and Process Heaters), published in the Federal Register March 21, 2011, affects new and existing boilers at major sources of HAP. According to the definitions, waste heat boilers are not affected sources, because they do not combust fuel. The 24.5 MMBTUH NSPS Subpart Dc boiler of EUG 19 is an affected source. Subpart DDDDD defines "new" as any boiler whose construction or reconstruction commenced after June 4, 2010, so the Dc boiler is an existing source. Because this boiler burns commercial natural gas, it is within the category designated in 40 CFR 63.7499(l) as "Units designed to burn natural gas, refinery gas or other gas 1 fuels." Although the boiler is an affected source, there are no standards that apply to it at present, but initial notification is a requirement. Subpart DDDDD currently indicates that compliance will be required by March 21, 2014.

CAM, 40 CFR Part 64

[Not Applicable]

This part applies to any pollutant-specific emissions unit at a major source that is required to obtain an operating permit, for any application for an initial operating permit submitted after April 20, 1998, that addresses "large pollutant-specific emissions units," or any application that addresses "large pollutant-specific emissions units" as a significant modification to an operating permit, or for any application for renewal of an operating permit, if it meets all of the following criteria.

- It is subject to an emission limit or standard for an applicable regulated air pollutant
- It uses a control device to achieve compliance with the applicable emission limit or standard
- It has potential emissions, prior to the control device, of the applicable regulated air pollutant of 100 TPY

The primary carbonizer, secondary carbonizer, east activation furnace, west activation furnace, and the regeneration furnace use afterburners to control emissions of VOC and toxic compounds. However, emissions after control are below 100 TPY for these pollutants and these specific processes are not potentially subject to the CAM rule until the renewal Title V permitting date. PM controls added per the Consent Order will require a CAM applicability review during renewal Title V permitting.

The coal handling facilities, coal dryer, regeneration kiln and acid wash facilities utilize baghouses and fabric filters to control emissions of PM. However, emissions after control are below 100 TPY for these pollutants and these specific processes are not subject to the CAM rule until the renewal Title V permitting date.

Chemical Accident Prevention Provisions, 40 CFR Part 68 [Not Applicable]
This facility does not process or store more than the threshold quantity of any regulated substance (Section 112r of the Clean Air Act 1990 Amendments).

Stratospheric Ozone Protection, 40 CFR Part 82 [Subparts B and F Applicable]
These standards require phase out of Class I & II substances, reductions of emissions of Class I & II substances to the lowest achievable level in all use sectors, and banning use of nonessential products containing ozone-depleting substances (Subparts A & C); control servicing of motor vehicle air conditioners (Subpart B); require Federal agencies to adopt procurement regulations that meet phase out requirements and that maximize the substitution of safe alternatives to Class I and Class II substances (Subpart D); require warning labels on products made with or containing Class I or II substances (Subpart E); maximize the use of recycling and recovery upon disposal (Subpart F); require producers to identify substitutes for ozone-depleting compounds under the Significant New Alternatives Program (Subpart G); and reduce the emissions of halons (Subpart H).

The facility performs service on motor (fleet) vehicles which involve ozone-depleting substances. Therefore, this facility is subject to these requirements and the permit requires compliance with Part 82 per Standard Condition XX.B.

SECTION IX. COMPLIANCE

Inspection

This retroactive PSD permit does not require an inspection independent from those performed in establishing the Part 70 operating permit.

Testing

Performance testing of PM emissions following the installation of cyclones was completed over the period of May 5 through May 15, 2009. These tests were not performed to demonstrate compliance with regulatory limits or with authorized emissions, but comparison of the results with either set of standards indicates that measured emissions were less than any of the requirements. Tests were run under varying conditions and the following table shows only the worst-case results.

| Source | Pounds per hour | | |
|----------------------------------|-----------------|-------------------------|-------------------------|
| | Measured | Calculated ¹ | Regulatory ² |
| New Activator Stack | 18.38 | 45.2 | 61.6 |
| Activator Boiler | 6.10 | 15.1 | 61.6 |
| Secondary Carbonizer Afterburner | 8.78 | 30.7 | 35.9 |
| Secondary Carbonizer Boiler | 5.22 | 30.7 | 35.9 |

¹ See Emissions (Section III).

² See Subchapter 19 discussion (Section VI).

Tier Classification and Public Review

This application has been determined to be a Tier II based on the request for a construction permit for an existing major stationary source. The permittee has submitted an affidavit that they are not seeking a permit for land use or for any operation upon land owned by others without their knowledge. The affidavit certifies that the applicant owns the land.

The applicant published the “Notice of Filing a Tier II Application” in *The Daily Times*, a daily newspaper in Mayes County, on February 10, 2008. The notice stated that the application was available for public review at the Pryor Public Library, Pryor, Oklahoma and at the AQD office in Oklahoma City. A draft of this permit will also be made available for public review for a period of 30 days as stated in another newspaper announcement and will be available for review on the Air Quality section of the DEQ web page at <http://www.deq.state.ok.us>. This facility is located within 50 miles of Oklahoma borders with Kansas, Missouri, and Arkansas. Notice of the draft permit has been provided to each of these states.

Fees Paid

Significant modification to a major source permit fee of \$1,500.

SECTION X. SUMMARY

Note that this permit is a retroactive PSD consideration of a completed project. This facility was constructed as described in the application. There are several active Air Quality compliance or enforcement issues, some of which are resolved by issuance of this permit, and some of which have no effect on issuance of this particular permit. Issuance of this permit for significant modification is recommended, contingent on public comment and EPA review.

DRAFT

PERMIT TO CONSTRUCT AIR POLLUTION CONTROL FACILITY SPECIFIC CONDITIONS

NORIT Americas, Inc.
Pryor Activated Carbon Facility

Permit Number 98-171-C (M-2) PSD

The permittee is authorized to construct in conformity with the specifications submitted to Air Quality on December 5, 2007, with modeling supplied at various times thereafter, in compliance with a Consent Order. The Evaluation Memorandum dated March 18, 2011, explains the derivation of applicable permit requirements and estimates of emissions; however, it does not contain operating limitations or permit requirements. The following Specific Conditions are identical to those found in Part 70 operating permit 98-171-TV. Continuing operations under this permit constitutes acceptance of, and consent to, the conditions contained herein.

1. Points of emissions and limitations for each point. [OAC 252:100-8-6(a)(1)]

EUG 1 Facility-wide

This emission unit group is facility-wide. It includes all emission units and is established to discuss the applicability of those rules or compliance demonstrations that may affect all sources within the facility.

EUG 2 Primary Carbonizer, Afterburner, and Waste Heat Boiler

| EU | Point ID | Name/Model | Const. Date |
|----|-----------|--------------------|-------------|
| 17 | SV-VP-005 | Primary Carbonizer | 1990 |

Emissions of NO_x and CO were authorized by Permit No. 88-105-O, while authorized emissions of particulate matter, treated as PM₁₀, and sulfur oxides, treated as SO₂, derive from the Consent Order mentioned above. Note that the SO₂ amount is shared among the primary carbonizer, secondary carbonizer, and the multiple hearth furnaces (activators), also identified as EU 17 (EUG 2), EU 12 (EUG 3), EU 10 and EU 11 (Both in EUG 6).

| Pollutant | NO _x | CO | PM | SO ₂ |
|-----------|-----------------|------|-----|-----------------|
| Lb/hr | 11.3 | 15.3 | N/A | N/A |
| TPY | 49.3 | 66.8 | 204 | 1,658 |

- a. The permittee is authorized to operate the primary carbonizer at a maximum raw material weight rate of nine tons per hour. [88-105-O]
- b. The primary carbonizer afterburner shall be operated: [88-105-O]
 - (1) at a temperature of not less than 1,650°F (upon issuance of this permit, this will be required to be a one hour rolling average);
 - (2) with residence time of the stack gases in the afterburners at least 2 seconds;
 - (3) with annual calibration of temperature monitoring device;
 - (4) with annual burner inspection;

- (5) continuously with the carbonizers; and
- (6) using only natural gas as defined in Part 72 having 20.0 grains/100 scf or less total sulfur.
- c. Recordkeeping requirements are listed in SC #14. [OAC 252:100-8-6 (a)(3)(B)]

EUG 3 Secondary Carbonizer, Cyclone, Afterburner, and Waste Heat Boiler

| EU | Point ID | Name/Model | Const. Date |
|----|--------------|----------------------|-------------|
| 12 | SV-VP-007a,b | Secondary Carbonizer | 1979/2006* |

*Multiclones added 11/2006

Authorized emissions of all pollutants derive from the Consent Order mentioned above. Note that the SO₂ amount is shared among the primary carbonizer, secondary carbonizer, and the multiple hearth furnaces (activators), also identified as EU 17 (EUG 2), EU 12 (EUG 3), EU 10 and EU 11 (Both in EUG 6).

| Pollutant | NO _x | CO | PM | SO ₂ |
|-----------|-----------------|------|-----|-----------------|
| TPY | 103 | 26.8 | 135 | 1,658 |

- a. The secondary carbonizer afterburner shall be operated: [Consent Order]
 - 1) at a temperature of not less than 1,650°F (upon issuance of this permit, this will be required to be a one hour rolling average);
 - 2) with annual calibration of temperature monitoring device;
 - 3) with annual burner inspection;
 - 4) continuously with the carbonizer; and
 - 5) using only natural gas as defined in Part 72 having 20.0 grains/100 scf or less total sulfur.
- b. The cyclone(s) shall be operated continuously whenever the waste heat boiler is being operated. The waste heat boiler and cyclone(s) may be bypassed. [Consent Order]
- c. The cyclones shall have external visual inspections to assure mechanical integrity and to identify any leaks (weekly).
- d. Recordkeeping requirements are listed in SC #14. [OAC 252:100-8-6 (a)(3)(B)]

EUG 4 Primary Carbonizer Heating Jacket

| EU | Point ID | Name/Model | Const. Date |
|----|-----------|-----------------------------------|-------------|
| 21 | SV-VP-006 | Primary Carbonizer Heating Jacket | 1990 |

Emissions authorized by Permit No. 88-105-O for EU 21 were based on AP-42 factors and no authorized emissions were published for EU 21. This Part 70 does not set emission limits, but the equipment shall remain as it is and emissions shall be calculated using the most current AP-42 factors.

- a. All fuel burning equipment shall only be fueled with pipeline quality natural gas. [88-105-O]
- b. Recordkeeping requirements are listed in SC #14. [OAC 252:100-8-6 (a)(3)(B)]

EUG 5 Secondary Carbonizer Heating Jacket

| EU | Point ID | Name/Model | Const. Date |
|----|-----------|-------------------------------------|-------------|
| 22 | SV-VP-008 | Secondary Carbonizer Heating Jacket | 1979 |

Emissions authorized by Permit No. 88-105-O for EU 22 were based on AP-42 factors and no authorized emissions were published for EU 22. This Part 70 does not set emission limits, but the equipment shall remain as it is and emissions shall be calculated using the most current AP-42 factors.

- b. All fuel burning equipment shall only be fueled with pipeline quality natural gas.[88-105-O]
- c. Recordkeeping requirements are listed in SC #14. [OAC 252:100-8-6 (a)(3)(B)]

EUG 6 Multiple Hearth Activation Furnaces (Area 30)

| EU | Point ID | Name/Model | Const. Date |
|----|---------------|---------------------------|-------------|
| 10 | SV-VP-009a, b | Activation Furnace – East | 1979 |
| 11 | SV-VP-010a, b | Activation Furnace – West | 1979 |

Each furnace has a dedicated cyclone and afterburner, but they share a common exhaust. There are two stacks, one of which is identified as “new.”

Authorized emissions of all pollutants derive from the Consent Order mentioned above. Note that the SO₂ amount is shared among the primary carbonizer, secondary carbonizer, and the multiple hearth furnaces (activators), also identified as EU 17 (EUG 2), EU 12 (EUG 3), EU 10 and EU 11 (Both in EUG 6).

Authorized Emissions (TPY)

| Unit Identity | NO _x | CO | PM | SO ₂ |
|---------------------|-----------------|------|------|-----------------|
| Activator Stack | 135 | 31.0 | 66.0 | 1,658 |
| New Activator Stack | 414 | 115 | 198 | |

- a. The east and west activation furnaces afterburners shall be operated as follows.
 - 1) At a temperature of not less than 1,650°F, upon issuance of this permit, this will be computed on a one hour rolling average.
 - 2) Annual calibration of temperature monitoring device
 - 3) Annual burner inspection
 - 4) Operated continuously with the carbonizers
 - 5) The afterburners shall be fueled only with pipeline quality natural gas.
- b. The activation furnace heaters shall only be fueled with pipeline quality natural gas.
- c. The cyclones shall have external visual inspections to assure mechanical integrity and to identify any leaks (weekly).
- d. Recordkeeping requirements are listed in SC #14. [OAC 252:100-8-6 (a)(3)(B)]

EUG 7 Acid Wash Plant Dryer

| EU | Point ID | Name/Model | Const. Date |
|----|-----------|-----------------------|-------------|
| 23 | SV-VP-015 | Acid Wash Plant Dryer | 1989 |

Emissions authorized by Permit No. 88-050-O (M-1) for EU 23 follow, updated to reflect current AP-42 factors for NO_x, CO, and VOC.

| Pollutant | NO _x | CO | VOC | PM | SO ₂ | HCl |
|-----------|-----------------|------|------|------|-----------------|------|
| Lb/hr | 0.59 | 0.50 | 0.03 | 1.59 | 0.01 | 4.09 |
| TPY | 2.58 | 2.16 | 0.14 | 3.48 | 0.02 | 9.38 |

- The permittee is authorized to operate the Acid Wash Plant not to exceed production of 15,000,000 pounds per year of activated carbon. [88-050-O (M-1)]
- All air discharges from the dryer, bagging operation, screening operation, and associated conveying equipment shall be processed by a baghouse or an equivalent PM emissions control device with a design efficiency of 98% or more. [88-050-O (M-1)]
- The permittee shall maintain accessible monitoring equipment to verify that the pressure drop across the baghouse is in accordance with manufacturer specifications. A copy of manufacturer's recommendations shall be available for inspection. [88-050-O (M-1)]
- The dryer shall be fired only with natural gas having 4 ppm or less sulfur. [88-050-O (M-1)]
- Recordkeeping requirements are listed in SC #14. [OAC 252:100-8-6 (a)(3)(B)]

EUG 8 Material Handling & Transfer – Controlled

| EU | Point ID | Description | Throughput |
|----|-----------|--|------------|
| 24 | SV-VP-004 | Transfer of coal From Area 20 to surge bin | 10 TPH |

EUG 9 Coal Processing Plant (Area 20)

Emissions from the Bowl Mill, Compactor, Crusher, Screener and Double Roll Crusher are processed by a single baghouse. Emissions from the coal dryer are processed by a separate baghouse.

| EU | Point ID | Name/Model | Const. Date |
|----|-----------|---|-------------|
| 8 | SV-VP-002 | Coal Preparation Plant Dryer | 1994 |
| 9 | SV-VP-003 | Coal Preparation Bowl Mill | 1994 |
| 9 | SV-VP-003 | Coal Preparation Compactor w/Crusher and Screener | 1994 |
| 9 | SV-VP-003 | Coal Preparation Double Roll Crusher | 1994 |

Particulate emissions authorized by Permit No. 93-025-O are as follow.

| EU # | Equipment | Emissions | |
|------|-----------------------|-----------|-------|
| | | Lb/hr | TPY |
| 8 | Dryer | 0.22 | 0.96 |
| 9 | Preparation equipment | 4.91 | 21.49 |

b. The permittee shall comply with the Standards of Performance for Coal Preparation Plants, NSPS Subpart Y, for each thermal dryer, coal processing and conveying equipment (including breakers and crushers), coal storage systems, and coal transfer and loading systems in the Coal Preparation Plant. [40 CFR 60.250 *et seq*]

1) The owner or operator shall not cause to be discharged into the atmosphere from the thermal dryer gases which contain particulate matter in excess of 0.070 g/dscm (0.031 gr/dscf), or exhibit 20 percent opacity or greater. [§ 60.252(a)(1) & (2)]

2) The owner or operator shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal, gases which exhibit 20 percent opacity or greater. [§ 60.252(c)]

3) The owner or operator shall install, calibrate, maintain, and continuously operate a monitoring device on the thermal dryer for the measurement of the temperature of the gas stream at the exit of the thermal dryer on a continuous basis. The monitoring device is to be certified by the manufacturer to be accurate within $\pm 3^\circ$ Fahrenheit and shall be replaced or recalibrated annually in accordance with procedures under §60.13(b). [§ 60.253]

c. Raw coal input shall not exceed 240 tons per day (TPD), monthly average. [93-025-O (M-1)]

d. The coal dryer shall be heated only with steam or other indirect heating such that no fuel-burning equipment becomes part of the unit. [93-025-O (M-1)]

e. All air discharges from the coal drying, milling, crushing, and screening operations shall be processed by a baghouse or an equivalent PM emissions control device with a design efficiency of 99% or more. [93-025-O (M-1)]

f. The permittee shall have available onsite a copy of the manufacturer's manual describing both proper operation of the control device and the parameters monitored to assure 99% efficiency. Monitored parameter(s) shall be recorded at least daily. [93-025-O (M-1)]

g. Recordkeeping requirements are listed in Specific Condition (SC) #14.

[OAC 252:100-8-6 (a)(3)(B)]

EUG10 Material Handling, Transfer, Traffic, & Erosion – Uncontrolled

Note that subbituminous is truncated to “subbit” for this table.

| EU | Point ID | Description | Throughput |
|-----------|-----------------|--|-------------------|
| 1a | VP10-SUB-01 | Subbit coal railcar unloading into hopper | 20 TPH |
| 1d | VP10-SUB-02 | Subbit coal drop to elevator from unloading hopper | 20 TPH |
| 1e | VP10-SUB-03 | Subbit coal drop from elevator to working subbit coal storage pile adjacent to unloading building | 20 TPH |
| 4 | VP10-SUB-05 | Front end loader drop into subbit coal storage pile in open storage area or in dry coal storage building | 20 TPH |
| 7 | VP10-SUB-10 | Front end loader drop of subbit coal into subbit coal loading hopper | 20 TPH |
| 2 | VP10-PIT-01 | Pitch railcar unloading into hopper | 20 TPH |
| 3 | VP10-PIT-02 | Pitch drop onto elevator from unloading hopper | 20 TPH |
| 1o | VP10-BIT-03 | Bituminous coal unloading from truck into bituminous unloading pile | 200TPH |
| 1 | VP10-BIT-05 | Front end loader drop of bituminous coal into coal storage area or dry coal storage building | 200 TPH |
| 7 | VP10-BIT-09 | Front end loader drop of bituminous coal into Load Hopper | 20 TPH |

| EU | Point ID | Description | Throughput |
|----|-------------|--|------------|
| 1 | VP10-REC-03 | Front end loader drop of Reclaim coal into truck | 120 TPH |
| 1 | VP10-REC-05 | Front end loader drop of Reclaim coal into Load Hopper | 20 TPH |
| 28 | VP40-PACLD | PAC Bulk loading station into trucks | 20 TPH |
| NA | SV-REGN-004 | Truck unloading onto SAC storage pad | 40 TPH |
| NA | REGN-SKUL | Regen F Hopper loading | 3 TPH |

EUG 11 Acid Wash Plant Material Handling & Transfer – Controlled

| EU | Point ID | Description | Throughput |
|----|-----------|--|------------|
| 23 | SV-VP-015 | Acid wash dryer drop to product screener | 1.5TPH |
| 23 | SV-VP-015 | Acid wash screener drop to product bin | 1.5TPH |
| 23 | SV-VP-015 | Acid wash plant product packaging | 1.5TPH |

EUG 12 Material Handling & Transfer – Controlled

| EU | Point ID | Description | Throughput |
|----|-----------|---|------------|
| 3 | SV-VP-001 | Pitch drop from elevator onto pitch building distribution conveyor belt | 35 TPH |
| 3 | SV-VP-003 | Pitch drop into Pitch feed Bin | 20 TPH |
| 13 | SV-VP-012 | Activated carbon from activated furnaces transfer into product screener and screening | 4 TPH |
| 13 | SV-VP-012 | Fines transfer from product screener to fines bin | 4 TPH |
| 13 | SV-VP-012 | Fines transfer from product screener to oversize bin | 4 TPH |
| 20 | SV-VP-013 | Transfer activated carbon from fines bin into PAC mill | 4 TPH |
| 13 | SV-VP-012 | PAC mill to packaging | 4 TPH |
| 13 | SV-VP-012 | Product screener transfer into packages | 4 TPH |
| 9 | SV-VP-003 | Activated carbon transfer into acid wash feed hopper | 4 TPH |

EUG 13 Material Handling, Transfer, Traffic, & Erosion – Uncontrolled

| EU | Point ID | Description | Throughput |
|----|-------------|---|------------|
| 4 | VP10-SUB-04 | Front end loader transfer from working storage to open subbituminous storage or dry coal storage building | 20 TPH |
| 5 | VP10-SUB-06 | Front end loader maintenance of subbituminous open coal storage area or dry coal storage area or dry coal storage building including transfer between open and dry coal storage building and to subbituminous coal loading hopper | 20 TPH |
| 4 | VP10-SUB-07 | Wind erosion of subbituminous coal working storage pile | |
| 6 | VP10-SUB-08 | Wind erosion of subbituminous coal storage pile | |
| 6 | VP10-SUB-09 | Wind erosion of subbituminous coal storage pile in dry coal storage building | |
| 3 | VP10-PIT-06 | Front end loader maintenance of pitch and transport to load hopper | 20 TPH |
| 1m | VP10-BIT-01 | Travel by truck carrying bituminous coal on unpaved road (Loaded) | |
| 7 | VP10-BIT-02 | Travel by truck carrying bituminous coal on unpaved road (Empty) | |
| 5 | VP10-BIT-04 | Movement of bituminous coal from unloading area to coal storage area or dry coal storage building by front end loader | 20 TPH |

| EU | Point ID | Description | Throughput |
|----|-------------|--|------------|
| 5 | VP10-BIT-06 | Maintenance of bituminous coal storage pile by front end loader and transfer to loading hopper | 20 TPH |
| 6 | VP10-BIT-07 | Wind erosion of bituminous coal in open coal storage area | |
| 6 | VP10-BIT-08 | Wind erosion of bituminous coal in dry coal storage building | |
| 5 | VP10-REC-01 | Loaded reclaim coal truck travel on unpaved roads | |
| 5 | VP10-REC-02 | Empty reclaim coal truck travel on unpaved roads | |
| 5 | VP10-REC-04 | Reclaim coal pile maintenance by loader, transfer to loading hopper | |
| 6 | VP10-REC-06 | Wind erosion of reclaim coal pile | |
| NA | SV-VP-004 | Wind erosion of SAC pile | |

EUG 14 Truck Unloading

| EU | Point ID | Description |
|----|-------------|---|
| NA | SV-REGN-001 | Truck loading into storage silos and transfer from storage to feed silo |
| NA | SV-REGN-002 | Truck unloading into auxiliary silo and neutralization |
| NA | SV-REGN-003 | Truck unloading into auxiliary silo and neutralization |

EUG 15 Regeneration Kiln/Afterburner

Emissions authorized for this EUG by Permit No. 90-006-O (M-3) follow.

| Pollutant | NO _x | CO | VOC | PM | SO ₂ | HCl |
|-----------|-----------------|------|------|------|-----------------|------|
| Lb/hr | 1.97 | 2.68 | 0.40 | 1.0 | 4.88 | 4.08 |
| TPY | 8.62 | 11.7 | 1.75 | 4.38 | 21.4 | 17.9 |

- a. The permittee shall be authorized to operate the regenerator kiln up to an annual production of 29,190,000 pounds per year (dry-basis) of activated carbon. [90-006-O (M-3)]
- b. All air discharges from the spent carbon receiving and product recovery operations shall be processed by a baghouse or an equivalent PM emissions control device with a design control efficiency of 99% or more. [90-006-O (M-3)]
- c. All air discharges from the rotary kiln shall be processed through: [90-006-O (M-3)]
 - 1) a baghouse or an equivalent PM emissions control device with an design control efficiency of 99% or more;
 - 2) an afterburner with a VOC design control efficiency of at least 99.99%;
 - 3) and an acid gas scrubber with a design control efficiency of at least 99% for HCl emissions control and 90% for SO₂ emissions control.
- d. The permittee shall operate the process off-gas baghouse with a pressure differential of at least 1.0 inch WC or as recommended by the manufacturer. [90-006-O (M-3)]
- e. The wet scrubber shall be operated: [90-006-O (M-3)]
 - 1) using liquid with a pH of 6.0 or greater, measured at least once each calendar day;
 - 2) with liquid supplied to the wet scrubber at a rate of at least 3 GPM; and
 - 3) with nozzle pressure of at least 20 psig, measured at least once each calendar day.
- f. Afterburner requirements follow. [90-006-O (M-4)]
 - 1) The afterburner shall be operated at a temperature not less than 1,600°F. Upon issuance of this permit, this will be required to be a one-hour rolling average.

- 2) Design of the afterburner shall provide a residence time of at least two seconds for stack gases.
 - 3) The temperature monitoring device shall be calibrated and the burner shall be inspected no less frequently than annually.
 - 4) The regeneration kiln shall not be operated unless the afterburner is functioning properly.
 - 5) Only pipeline quality natural gas with sulfur content less than or equal to 4 ppm shall be used as pilot fuel for the afterburner.
 - 6) If the regeneration kiln handles chlorinated organic waste material, the afterburner shall be operated at a temperature not less than 1,775°F, 24-hour rolling average. Chlorinated organic waste, as used here, means any material listed in 40 CFR 261.24 that is present in the material to be regenerated in concentrations equal to or greater than the “regulatory level” shown in §261.24.
- g. The facility shall maintain records of all waste stream profiles, sufficient to demonstrate the presence of any chlorinated organic waste in each, along with records sufficient to demonstrate when each such stream was processed through the regeneration kiln and afterburner. [90-006-O (M-3)]
- h. The permittee shall conduct weekly visual observations of the opacity from the exhausts associated with these emission units using EPA Reference Method 22 and keep a record of these observations. If visible emissions are detected, then the permittee shall conduct a thirty-minute opacity reading in accordance with EPA Reference Method No. 9. [90-006-O (M-3)]
- i. Recordkeeping requirements are listed in SC #14. [OAC 252:100-8-6 (a)(3)(B)]

EUG 16 Regenerator Plant Material Handling

Permit No. 90-006-O (M-3) authorizes silo vent particulate emissions of 4.80 lbs/hr and 1.15 TPY. It also requires that any replacement of the existing baghouse have at least 99% capture design efficiency.

| EU | Point | Description | Throughput |
|----|-------------|--|------------|
| 19 | SV-REGN-003 | Packaging area material handling | 2 |
| NA | SV-REGN-004 | Regeneration product collector | 2 |
| NA | REGN-TRKLD | Regen bulk truck loading (drop into top of trucks at facility on northwest side of regeneration plant) | 20 |

EUG 17 Regenerator Plant Bulk Handling

Permit No. 90-006-O (M-3) authorizes product handling particulate emissions of 1.46 lbs/hr and 6.57 TPY. It also requires that any replacement of the existing baghouse have at least 99% capture efficiency.

| EU | Point ID | Description |
|----|------------|--|
| 27 | REGN-PACLD | Regeneration plant PAC mill bulk truck loadout |

EUG 18 Hydrochloric acid Storage Tank

| EU | Point ID | Description | Const. Date |
|----|-----------|--------------|-------------|
| 15 | SV-VP-016 | Storage tank | Unknown |

EUG 19 NSPS Subpart Dc Boiler (Permit No. 98-171-C (M-1))

| EU | Point | Description | Const. Date |
|----|-----------|------------------------------------|-------------|
| 19 | SV-VP-019 | 24.5 MMBTUH Cleaver-Brooks CBLE600 | 1/18/2008 |

EUG 20 Cooling Tower

The cooling tower is estimated to emit 0.02 lbs/hr of particulate. The applicable limit according to Appendix G is 74 lbs/hr. All particulates is assumed to be PM₁₀.

| EU | Point | Description |
|----|-----------|---------------|
| 20 | SV-VP-020 | Cooling Tower |

2. The permittee shall be authorized to operate this facility continuously (24 hours per day, every day of the year). [OAC 252:100-8-6(a)]

3. The fuel-burning equipment shall use pipeline-grade natural gas. [OAC 252:100-31]

4. Each emission unit at the facility shall have a permanent identification plate attached which shows the make, model number, and serial number. [OAC 252:100-43]

5. The permittee shall keep operation and maintenance (O&M) records for all emission units that have not been modified under a construction permit. Such records shall at a minimum include the dates of operation, and maintenance, type of work performed, and the increase, if any, in emissions as a result.

[OAC 252:100-8-6 (a)(3)(B)]

6. Performance testing for various pollutants shall be performed at certain vents to atmosphere no less frequently than every five years. Vents subject to testing include the primary carbonizer, the secondary carbonizer, and the activation hearths. Testing shall occur downstream from all control devices. Pollutants to be tested include oxides of nitrogen (NO_x), carbon monoxide (CO), oxides of sulfur (SO_x), volatile organic compounds (VOC), and particulate matter (PM). PM testing shall address those aerodynamic diameters for which standards have been set, such as PM₁₀ and PM_{2.5}. PM testing shall include both filterable (front half) and condensable (back half) emissions. Testing shall be performed in a timely manner so that results will be supplied to DEQ in subsequent applications for Title V renewal. In the event that continuous emissions monitoring (CEMs) equipment is installed on any vent, RATA testing of the CEMs shall demonstrate compliance with this Condition.

[OAC 252:100-8-6 (a)(3)(A)]

7. When periodic compliance testing shows emissions in excess of the lb/hr emission limits in Specific Condition Number 1, the permittee shall comply with the provisions of OAC 252:100-9 for excess emissions. Requirements of OAC 252:100-9 include immediate notification and

written notification of Air Quality and demonstrations that the excess emissions meet the criteria specified in OAC 252:100-9. [OAC 252:100-9]

8. The permittee shall conduct weekly visual observations of the opacity from the exhausts associated with screening and crushing emission units in EUGs 2, 5, 12 and 16 using EPA Reference Method 22, and keep a record of these observations. If visible emissions are detected, then the permittee shall conduct a thirty-minute opacity reading in accordance with EPA Reference Method No. 9. [OAC 252:100-43]

9. The 24.5 MMBTU boiler of EUG 19 is an affected facility under 40 CFR 60, Subpart Dc, and is subject to the following requirements. [98-171-C (M-1), 40 CFR 60.60c *et seq*]

- a) Consumption of natural gas not to exceed 214,620 MMBTUs per rolling 12-month total.
- b) Records of amount of fuel combusted. (daily, monthly and 12-month rolling total).

10. The 24.5 MMBTU boiler of EUG 19 is an affected facility under 40 CFR 63, Subpart DDDDD, and is subject to the requirements of that subpart. The compliance date is projected to be March 21, 2014. [40 CFR 63.7480 *et seq*]

11. Emissions of SO₂ from the VAC shall be calculated based on material balance for the entire process. The sulfur content of the raw material (feed) is known or measurable, as is the sulfur content of the product. The difference in total sulfur between feed and product shall be considered to have been converted to sulfur dioxide stoichiometrically and emitted. The permittee may assign portions of the total to each of the primary carbonizer, secondary carbonizer, and activator hearths, based on reasonable assumptions about sulfur lost in each. Product shall be tested for sulfur content to determine both the amount of sulfur present and the ratio of sulfur in the product to sulfur in the feed. Bituminous and subbituminous coals shall be tested at least twice each during each calendar year, with no test for each type of feed occurring sooner than 120 days after the preceding test. For the first year after this permit is issued, the permittee may assume the ratio to be 90%. If four consecutive tests of either type of feed show that 90% results in conservatively high emissions, the permittee may discontinue testing and simply use 90% for that type. If testing shows ratios less than 90%, actual ratios shall be used in subsequent years. If testing shows consistent ratios, permittee may request discontinuance of testing. Because test data and emission calculations may reveal proprietary information relative to the process, only the results shall be necessary for emission inventory purposes. However, all confidential data and supporting assumptions and calculations shall be made available to DEQ for inspections and as otherwise required. [OAC 252:100-43]

12. Emissions of particulate matter (PM) from the VAC shall be calculated as PM₁₀ or PM_{2.5} based on material balance for the entire process. The method is more complicated than that laid out in SC #10 for SO₂ in that a combustible solid is being processed. Certain portions of the material may be oxidized and be emitted as a gas, while other portions have been oxidized and are fully capable of being emitted as PM. The permittee shall provide an analysis demonstrating the calculation of emissions, showing the ash content at various stages of the VAC process and explaining each calculation. Because test data and emission calculations may reveal proprietary information relative to the process, only the results shall be necessary for emission inventory

purposes. However, all confidential data and supporting assumptions and calculations shall be made available to DEQ for inspections and as otherwise required. [OAC 252:100-43]

13. The following records shall be maintained on site to verify Insignificant Activities. No recordkeeping is required for those operations that qualify as Trivial Activities.

[OAC 252:100-8-6 (a)(3)(B)]

- a) For stationary reciprocating engines used exclusively for emergency power generation or for peaking power service, records of the size of engines, type of fuel used, and number of hours operated (annual).
- b) For fuel storage/dispensing equipment operated solely for facility owned vehicles, records of the type and amount of fuel dispensed (annual).
- c) For fluid storage tanks with a capacity of less than 39,894 gallons and a true vapor pressure less than 1.5 psia, records of the capacity of the tanks and the contents.
- d) For activities (except for trivial activities) that have the potential to emit less than 5 TPY (actual) of any criteria pollutant, the type of activity and the amount of emissions or a surrogate measure of the activity (annual).

14. The permittee shall maintain records of operations as listed below. These records shall be maintained on site or at a local field office for at least five years after the date of recording and shall be provided to regulatory personnel upon request.

[OAC 252:100-8-6 (a)(3)(B)]

- a) Natural gas usage for each combustion unit – EUGs 2, 3, 4, 5, 6, 7 & 15 (monthly and 12-month rolling total)
- b) Feed coal characterization – EUG 9 (each change of supply)
- c) Baghouse pressure differentials, or other parameters, as appropriate – EUG 9 (daily).
- d) Thermal dryer outlet temperature – EUG 9 (calendar day average)
- e) Process weight rates and hours of operation for each carbonizer – EUGs 2 & 3 (daily). The process weight rates for the secondary carbonizer can be estimated based on expected yields from the primary carbonizer.
- f) Sulfur content of the coal being processed – EUGs 2 & 3 (each change of input)
- g) Temperature of the afterburners during operation – EUGs 2, 3, 6, & 15 (upon issuance of this permit, these will be required to be one hour averages).
- h) Activated carbon production – EUGs 6, 7 & 15 (monthly and 12-month rolling total).
- i) Baghouse pressure differentials – EUGs, 7, 8, 9, 10, 12, 15, & 16 (daily).
- j) Process weight rates and hours of operation for each furnace – EUG 6 (daily). Process weights can be estimated based on the expected yields from the carbonizers.
- k) Scrubber nozzle pressures - EUG 15 (daily).
- l) Acid gas scrubber liquor pH - EUG 15 (daily).
- m) Operation, maintenance, and inspection log for each control device – all EUGs.
- n) Records of the date and time of Reference Method (RM) No. 22 visual emission observations, stack or emission point observed, operational status of the emission unit, observed results and conclusions, and any RM No. 9 results.- EUGs 4, 5, 10, 12, 13 & 16 (as needed).
- o) Amount of fuel combusted – EUG 19 (daily, monthly and 12-month rolling total).

- p) The facility shall maintain records of all waste stream profiles, sufficient to demonstrate the presence of any chlorinated organic waste in each, along with records sufficient to demonstrate when each such stream was processed through the regeneration kiln and afterburner.
- q) Records of weekly external inspections of cyclones and of O&M, per SC #1, EUG 3 and EUG 6.

COMPLIANCE PLAN

- a. Norit can effectively address all SO₂ requirements through emissions controls or enhanced dispersion coupled with reduced allowable emission limits. Both options will require further study before a selection can be made. Also, adequate time will be needed to design and construct the selected project.
- b. Within one (1) year of the issue date of this PSD permit, Norit agrees to complete the evaluation and present plans to DEQ for the selected project.
- c. Within three (3) years of the issue date of this PSD permit, Norit agrees to have the selected project completed.
- d. If the method involves performance testing, such testing shall be completed within six months after first operation of the method chosen.

**MAJOR SOURCE AIR QUALITY PERMIT
STANDARD CONDITIONS
(July 21, 2009)**

SECTION I. DUTY TO COMPLY

A. This is a permit to operate / construct this specific facility in accordance with the federal Clean Air Act (42 U.S.C. 7401, et al.) and under the authority of the Oklahoma Clean Air Act and the rules promulgated there under. [Oklahoma Clean Air Act, 27A O.S. § 2-5-112]

B. The issuing Authority for the permit is the Air Quality Division (AQD) of the Oklahoma Department of Environmental Quality (DEQ). The permit does not relieve the holder of the obligation to comply with other applicable federal, state, or local statutes, regulations, rules, or ordinances. [Oklahoma Clean Air Act, 27A O.S. § 2-5-112]

C. The permittee shall comply with all conditions of this permit. Any permit noncompliance shall constitute a violation of the Oklahoma Clean Air Act and shall be grounds for enforcement action, permit termination, revocation and reissuance, or modification, or for denial of a permit renewal application. All terms and conditions are enforceable by the DEQ, by the Environmental Protection Agency (EPA), and by citizens under section 304 of the Federal Clean Air Act (excluding state-only requirements). This permit is valid for operations only at the specific location listed.

[40 C.F.R. §70.6(b), OAC 252:100-8-1.3 and OAC 252:100-8-6(a)(7)(A) and (b)(1)]

D. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit. However, nothing in this paragraph shall be construed as precluding consideration of a need to halt or reduce activity as a mitigating factor in assessing penalties for noncompliance if the health, safety, or environmental impacts of halting or reducing operations would be more serious than the impacts of continuing operations. [OAC 252:100-8-6(a)(7)(B)]

SECTION II. REPORTING OF DEVIATIONS FROM PERMIT TERMS

A. Any exceedance resulting from an emergency and/or posing an imminent and substantial danger to public health, safety, or the environment shall be reported in accordance with Section XIV (Emergencies). [OAC 252:100-8-6(a)(3)(C)(iii)(I) & (II)]

B. Deviations that result in emissions exceeding those allowed in this permit shall be reported consistent with the requirements of OAC 252:100-9, Excess Emission Reporting Requirements. [OAC 252:100-8-6(a)(3)(C)(iv)]

C. Every written report submitted under this section shall be certified as required by Section III (Monitoring, Testing, Recordkeeping & Reporting), Paragraph F. [OAC 252:100-8-6(a)(3)(C)(iv)]

SECTION III. MONITORING, TESTING, RECORDKEEPING & REPORTING

A. The permittee shall keep records as specified in this permit. These records, including monitoring data and necessary support information, shall be retained on-site or at a nearby field office for a period of at least five years from the date of the monitoring sample, measurement, report, or application, and shall be made available for inspection by regulatory personnel upon request. Support information includes all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. Where appropriate, the permit may specify that records may be maintained in computerized form.

[OAC 252:100-8-6 (a)(3)(B)(ii), OAC 252:100-8-6(c)(1), and OAC 252:100-8-6(c)(2)(B)]

B. Records of required monitoring shall include:

- (1) the date, place and time of sampling or measurement;
- (2) the date or dates analyses were performed;
- (3) the company or entity which performed the analyses;
- (4) the analytical techniques or methods used;
- (5) the results of such analyses; and
- (6) the operating conditions existing at the time of sampling or measurement.

[OAC 252:100-8-6(a)(3)(B)(i)]

C. No later than 30 days after each six (6) month period, after the date of the issuance of the original Part 70 operating permit or alternative date as specifically identified in a subsequent Part 70 operating permit, the permittee shall submit to AQD a report of the results of any required monitoring. All instances of deviations from permit requirements since the previous report shall be clearly identified in the report. Submission of these periodic reports will satisfy any reporting requirement of Paragraph E below that is duplicative of the periodic reports, if so noted on the submitted report.

[OAC 252:100-8-6(a)(3)(C)(i) and (ii)]

D. If any testing shows emissions in excess of limitations specified in this permit, the owner or operator shall comply with the provisions of Section II (Reporting Of Deviations From Permit Terms) of these standard conditions.

[OAC 252:100-8-6(a)(3)(C)(iii)]

E. In addition to any monitoring, recordkeeping or reporting requirement specified in this permit, monitoring and reporting may be required under the provisions of OAC 252:100-43, Testing, Monitoring, and Recordkeeping, or as required by any provision of the Federal Clean Air Act or Oklahoma Clean Air Act.

[OAC 252:100-43]

F. Any Annual Certification of Compliance, Semi Annual Monitoring and Deviation Report, Excess Emission Report, and Annual Emission Inventory submitted in accordance with this permit shall be certified by a responsible official. This certification shall be signed by a responsible official, and shall contain the following language: "I certify, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete."

[OAC 252:100-8-5(f), OAC 252:100-8-6(a)(3)(C)(iv), OAC 252:100-8-6(c)(1), OAC 252:100-9-7(e), and OAC 252:100-5-2.1(f)]

G. Any owner or operator subject to the provisions of New Source Performance Standards (“NSPS”) under 40 CFR Part 60 or National Emission Standards for Hazardous Air Pollutants (“NESHAPs”) under 40 CFR Parts 61 and 63 shall maintain a file of all measurements and other information required by the applicable general provisions and subpart(s). These records shall be maintained in a permanent file suitable for inspection, shall be retained for a period of at least five years as required by Paragraph A of this Section, and shall include records of the occurrence and duration of any start-up, shutdown, or malfunction in the operation of an affected facility, any malfunction of the air pollution control equipment; and any periods during which a continuous monitoring system or monitoring device is inoperative.

[40 C.F.R. §§60.7 and 63.10, 40 CFR Parts 61, Subpart A, and OAC 252:100, Appendix Q]

H. The permittee of a facility that is operating subject to a schedule of compliance shall submit to the DEQ a progress report at least semi-annually. The progress reports shall contain dates for achieving the activities, milestones or compliance required in the schedule of compliance and the dates when such activities, milestones or compliance was achieved. The progress reports shall also contain an explanation of why any dates in the schedule of compliance were not or will not be met, and any preventive or corrective measures adopted. [OAC 252:100-8-6(c)(4)]

I. All testing must be conducted under the direction of qualified personnel by methods approved by the Division Director. All tests shall be made and the results calculated in accordance with standard test procedures. The use of alternative test procedures must be approved by EPA. When a portable analyzer is used to measure emissions it shall be setup, calibrated, and operated in accordance with the manufacturer’s instructions and in accordance with a protocol meeting the requirements of the “AQD Portable Analyzer Guidance” document or an equivalent method approved by Air Quality.

[OAC 252:100-8-6(a)(3)(A)(iv), and OAC 252:100-43]

J. The reporting of total particulate matter emissions as required in Part 7 of OAC 252:100-8 (Permits for Part 70 Sources), OAC 252:100-19 (Control of Emission of Particulate Matter), and OAC 252:100-5 (Emission Inventory), shall be conducted in accordance with applicable testing or calculation procedures, modified to include back-half condensables, for the concentration of particulate matter less than 10 microns in diameter (PM₁₀). NSPS may allow reporting of only particulate matter emissions caught in the filter (obtained using Reference Method 5).

K. The permittee shall submit to the AQD a copy of all reports submitted to the EPA as required by 40 C.F.R. Part 60, 61, and 63, for all equipment constructed or operated under this permit subject to such standards. [OAC 252:100-8-6(c)(1) and OAC 252:100, Appendix Q]

SECTION IV. COMPLIANCE CERTIFICATIONS

A. No later than 30 days after each anniversary date of the issuance of the original Part 70 operating permit or alternative date as specifically identified in a subsequent Part 70 operating permit, the permittee shall submit to the AQD, with a copy to the US EPA, Region 6, a certification of compliance with the terms and conditions of this permit and of any other applicable requirements which have become effective since the issuance of this permit.

[OAC 252:100-8-6(c)(5)(A), and (D)]

B. The compliance certification shall describe the operating permit term or condition that is the basis of the certification; the current compliance status; whether compliance was continuous or intermittent; the methods used for determining compliance, currently and over the reporting period. The compliance certification shall also include such other facts as the permitting authority may require to determine the compliance status of the source.

[OAC 252:100-8-6(c)(5)(C)(i)-(v)]

C. The compliance certification shall contain a certification by a responsible official as to the results of the required monitoring. This certification shall be signed by a responsible official, and shall contain the following language: "I certify, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete."

[OAC 252:100-8-5(f) and OAC 252:100-8-6(c)(1)]

D. Any facility reporting noncompliance shall submit a schedule of compliance for emissions units or stationary sources that are not in compliance with all applicable requirements. This schedule shall include a schedule of remedial measures, including an enforceable sequence of actions with milestones, leading to compliance with any applicable requirements for which the emissions unit or stationary source is in noncompliance. This compliance schedule shall resemble and be at least as stringent as that contained in any judicial consent decree or administrative order to which the emissions unit or stationary source is subject. Any such schedule of compliance shall be supplemental to, and shall not sanction noncompliance with, the applicable requirements on which it is based, except that a compliance plan shall not be required for any noncompliance condition which is corrected within 24 hours of discovery.

[OAC 252:100-8-5(e)(8)(B) and OAC 252:100-8-6(c)(3)]

SECTION V. REQUIREMENTS THAT BECOME APPLICABLE DURING THE PERMIT TERM

The permittee shall comply with any additional requirements that become effective during the permit term and that are applicable to the facility. Compliance with all new requirements shall be certified in the next annual certification.

[OAC 252:100-8-6(c)(6)]

SECTION VI. PERMIT SHIELD

A. Compliance with the terms and conditions of this permit (including terms and conditions established for alternate operating scenarios, emissions trading, and emissions averaging, but excluding terms and conditions for which the permit shield is expressly prohibited under OAC 252:100-8) shall be deemed compliance with the applicable requirements identified and included in this permit.

[OAC 252:100-8-6(d)(1)]

B. Those requirements that are applicable are listed in the Standard Conditions and the Specific Conditions of this permit. Those requirements that the applicant requested be determined as not applicable are summarized in the Specific Conditions of this permit.

[OAC 252:100-8-6(d)(2)]

SECTION VII. ANNUAL EMISSIONS INVENTORY & FEE PAYMENT

The permittee shall file with the AQD an annual emission inventory and shall pay annual fees based on emissions inventories. The methods used to calculate emissions for inventory purposes shall be based on the best available information accepted by AQD.

[OAC 252:100-5-2.1, OAC 252:100-5-2.2, and OAC 252:100-8-6(a)(8)]

SECTION VIII. TERM OF PERMIT

A. Unless specified otherwise, the term of an operating permit shall be five years from the date of issuance. [OAC 252:100-8-6(a)(2)(A)]

B. A source's right to operate shall terminate upon the expiration of its permit unless a timely and complete renewal application has been submitted at least 180 days before the date of expiration. [OAC 252:100-8-7.1(d)(1)]

C. A duly issued construction permit or authorization to construct or modify will terminate and become null and void (unless extended as provided in OAC 252:100-8-1.4(b)) if the construction is not commenced within 18 months after the date the permit or authorization was issued, or if work is suspended for more than 18 months after it is commenced. [OAC 252:100-8-1.4(a)]

D. The recipient of a construction permit shall apply for a permit to operate (or modified operating permit) within 180 days following the first day of operation. [OAC 252:100-8-4(b)(5)]

SECTION IX. SEVERABILITY

The provisions of this permit are severable and if any provision of this permit, or the application of any provision of this permit to any circumstance, is held invalid, the application of such provision to other circumstances, and the remainder of this permit, shall not be affected thereby. [OAC 252:100-8-6 (a)(6)]

SECTION X. PROPERTY RIGHTS

A. This permit does not convey any property rights of any sort, or any exclusive privilege. [OAC 252:100-8-6(a)(7)(D)]

B. This permit shall not be considered in any manner affecting the title of the premises upon which the equipment is located and does not release the permittee from any liability for damage to persons or property caused by or resulting from the maintenance or operation of the equipment for which the permit is issued. [OAC 252:100-8-6(c)(6)]

SECTION XI. DUTY TO PROVIDE INFORMATION

A. The permittee shall furnish to the DEQ, upon receipt of a written request and within sixty (60) days of the request unless the DEQ specifies another time period, any information that the DEQ may request to determine whether cause exists for modifying, reopening, revoking,

reissuing, terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the DEQ copies of records required to be kept by the permit.

[OAC 252:100-8-6(a)(7)(E)]

B. The permittee may make a claim of confidentiality for any information or records submitted pursuant to 27A O.S. § 2-5-105(18). Confidential information shall be clearly labeled as such and shall be separable from the main body of the document such as in an attachment.

[OAC 252:100-8-6(a)(7)(E)]

C. Notification to the AQD of the sale or transfer of ownership of this facility is required and shall be made in writing within thirty (30) days after such sale or transfer.

[Oklahoma Clean Air Act, 27A O.S. § 2-5-112(G)]

SECTION XII. REOPENING, MODIFICATION & REVOCATION

A. The permit may be modified, revoked, reopened and reissued, or terminated for cause. Except as provided for minor permit modifications, the filing of a request by the permittee for a permit modification, revocation and reissuance, termination, notification of planned changes, or anticipated noncompliance does not stay any permit condition.

[OAC 252:100-8-6(a)(7)(C) and OAC 252:100-8-7.2(b)]

B. The DEQ will reopen and revise or revoke this permit prior to the expiration date in the following circumstances:

[OAC 252:100-8-7.3 and OAC 252:100-8-7.4(a)(2)]

- (1) Additional requirements under the Clean Air Act become applicable to a major source category three or more years prior to the expiration date of this permit. No such reopening is required if the effective date of the requirement is later than the expiration date of this permit.
- (2) The DEQ or the EPA determines that this permit contains a material mistake or that the permit must be revised or revoked to assure compliance with the applicable requirements.
- (3) The DEQ or the EPA determines that inaccurate information was used in establishing the emission standards, limitations, or other conditions of this permit. The DEQ may revoke and not reissue this permit if it determines that the permittee has submitted false or misleading information to the DEQ.
- (4) DEQ determines that the permit should be amended under the discretionary reopening provisions of OAC 252:100-8-7.3(b).

C. The permit may be reopened for cause by EPA, pursuant to the provisions of OAC 100-8-7.3(d).

[OAC 100-8-7.3(d)]

D. The permittee shall notify AQD before making changes other than those described in Section XVIII (Operational Flexibility), those qualifying for administrative permit amendments, or those defined as an Insignificant Activity (Section XVI) or Trivial Activity (Section XVII). The notification should include any changes which may alter the status of a “grandfathered source,” as defined under AQD rules. Such changes may require a permit modification.

[OAC 252:100-8-7.2(b) and OAC 252:100-5-1.1]

E. Activities that will result in air emissions that exceed the trivial/insignificant levels and that are not specifically approved by this permit are prohibited. [OAC 252:100-8-6(c)(6)]

SECTION XIII. INSPECTION & ENTRY

A. Upon presentation of credentials and other documents as may be required by law, the permittee shall allow authorized regulatory officials to perform the following (subject to the permittee's right to seek confidential treatment pursuant to 27A O.S. Supp. 1998, § 2-5-105(18) for confidential information submitted to or obtained by the DEQ under this section):

- (1) enter upon the permittee's premises during reasonable/normal working hours where a source is located or emissions-related activity is conducted, or where records must be kept under the conditions of the permit;
- (2) have access to and copy, at reasonable times, any records that must be kept under the conditions of the permit;
- (3) inspect, at reasonable times and using reasonable safety practices, any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit; and
- (4) as authorized by the Oklahoma Clean Air Act, sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the permit.

[OAC 252:100-8-6(c)(2)]

SECTION XIV. EMERGENCIES

A. Any exceedance resulting from an emergency shall be reported to AQD promptly but no later than 4:30 p.m. on the next working day after the permittee first becomes aware of the exceedance. This notice shall contain a description of the emergency, the probable cause of the exceedance, any steps taken to mitigate emissions, and corrective actions taken.

[OAC 252:100-8-6 (a)(3)(C)(iii)(I) and (IV)]

B. Any exceedance that poses an imminent and substantial danger to public health, safety, or the environment shall be reported to AQD as soon as is practicable; but under no circumstance shall notification be more than 24 hours after the exceedance. [OAC 252:100-8-6(a)(3)(C)(iii)(II)]

C. An "emergency" means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under this permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventive maintenance, careless or improper operation, or operator error. [OAC 252:100-8-2]

D. The affirmative defense of emergency shall be demonstrated through properly signed, contemporaneous operating logs or other relevant evidence that: [OAC 252:100-8-6 (e)(2)]

- (1) an emergency occurred and the permittee can identify the cause or causes of the emergency;
- (2) the permitted facility was at the time being properly operated;
- (3) during the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards or other requirements in this permit.

E. In any enforcement proceeding, the permittee seeking to establish the occurrence of an emergency shall have the burden of proof. [OAC 252:100-8-6(e)(3)]

F. Every written report or document submitted under this section shall be certified as required by Section III (Monitoring, Testing, Recordkeeping & Reporting), Paragraph F. [OAC 252:100-8-6(a)(3)(C)(iv)]

SECTION XV. RISK MANAGEMENT PLAN

The permittee, if subject to the provision of Section 112(r) of the Clean Air Act, shall develop and register with the appropriate agency a risk management plan by June 20, 1999, or the applicable effective date. [OAC 252:100-8-6(a)(4)]

SECTION XVI. INSIGNIFICANT ACTIVITIES

Except as otherwise prohibited or limited by this permit, the permittee is hereby authorized to operate individual emissions units that are either on the list in Appendix I to OAC Title 252, Chapter 100, or whose actual calendar year emissions do not exceed any of the limits below. Any activity to which a State or Federal applicable requirement applies is not insignificant even if it meets the criteria below or is included on the insignificant activities list.

- (1) 5 tons per year of any one criteria pollutant.
- (2) 2 tons per year for any one hazardous air pollutant (HAP) or 5 tons per year for an aggregate of two or more HAP's, or 20 percent of any threshold less than 10 tons per year for single HAP that the EPA may establish by rule.

[OAC 252:100-8-2 and OAC 252:100, Appendix I]

SECTION XVII. TRIVIAL ACTIVITIES

Except as otherwise prohibited or limited by this permit, the permittee is hereby authorized to operate any individual or combination of air emissions units that are considered inconsequential and are on the list in Appendix J. Any activity to which a State or Federal applicable requirement applies is not trivial even if included on the trivial activities list.

[OAC 252:100-8-2 and OAC 252:100, Appendix J]

SECTION XVIII. OPERATIONAL FLEXIBILITY

A. A facility may implement any operating scenario allowed for in its Part 70 permit without the need for any permit revision or any notification to the DEQ (unless specified otherwise in the

permit). When an operating scenario is changed, the permittee shall record in a log at the facility the scenario under which it is operating. [OAC 252:100-8-6(a)(10) and (f)(1)]

B. The permittee may make changes within the facility that:

- (1) result in no net emissions increases,
- (2) are not modifications under any provision of Title I of the federal Clean Air Act, and
- (3) do not cause any hourly or annual permitted emission rate of any existing emissions unit to be exceeded;

provided that the facility provides the EPA and the DEQ with written notification as required below in advance of the proposed changes, which shall be a minimum of seven (7) days, or twenty four (24) hours for emergencies as defined in OAC 252:100-8-6 (e). The permittee, the DEQ, and the EPA shall attach each such notice to their copy of the permit. For each such change, the written notification required above shall include a brief description of the change within the permitted facility, the date on which the change will occur, any change in emissions, and any permit term or condition that is no longer applicable as a result of the change. The permit shield provided by this permit does not apply to any change made pursuant to this paragraph. [OAC 252:100-8-6(f)(2)]

SECTION XIX. OTHER APPLICABLE & STATE-ONLY REQUIREMENTS

A. The following applicable requirements and state-only requirements apply to the facility unless elsewhere covered by a more restrictive requirement:

- (1) Open burning of refuse and other combustible material is prohibited except as authorized in the specific examples and under the conditions listed in the Open Burning Subchapter. [OAC 252:100-13]
- (2) No particulate emissions from any fuel-burning equipment with a rated heat input of 10 MMBTUH or less shall exceed 0.6 lb/MMBTU. [OAC 252:100-19]
- (3) For all emissions units not subject to an opacity limit promulgated under 40 C.F.R., Part 60, NSPS, no discharge of greater than 20% opacity is allowed except for: [OAC 252:100-25]
 - (a) Short-term occurrences which consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity;
 - (b) Smoke resulting from fires covered by the exceptions outlined in OAC 252:100-13-7;
 - (c) An emission, where the presence of uncombined water is the only reason for failure to meet the requirements of OAC 252:100-25-3(a); or
 - (d) Smoke generated due to a malfunction in a facility, when the source of the fuel producing the smoke is not under the direct and immediate control of the facility and the immediate constriction of the fuel flow at the facility would produce a hazard to life and/or property.

- (4) No visible fugitive dust emissions shall be discharged beyond the property line on which the emissions originate in such a manner as to damage or to interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or interfere with the maintenance of air quality standards. [OAC 252:100-29]
- (5) No sulfur oxide emissions from new gas-fired fuel-burning equipment shall exceed 0.2 lb/MMBTU. No existing source shall exceed the listed ambient air standards for sulfur dioxide. [OAC 252:100-31]
- (6) Volatile Organic Compound (VOC) storage tanks built after December 28, 1974, and with a capacity of 400 gallons or more storing a liquid with a vapor pressure of 1.5 psia or greater under actual conditions shall be equipped with a permanent submerged fill pipe or with a vapor-recovery system. [OAC 252:100-37-15(b)]
- (7) All fuel-burning equipment shall at all times be properly operated and maintained in a manner that will minimize emissions of VOCs. [OAC 252:100-37-36]

SECTION XX. STRATOSPHERIC OZONE PROTECTION

A. The permittee shall comply with the following standards for production and consumption of ozone-depleting substances: [40 CFR 82, Subpart A]

- (1) Persons producing, importing, or placing an order for production or importation of certain class I and class II substances, HCFC-22, or HCFC-141b shall be subject to the requirements of §82.4;
- (2) Producers, importers, exporters, purchasers, and persons who transform or destroy certain class I and class II substances, HCFC-22, or HCFC-141b are subject to the recordkeeping requirements at §82.13; and
- (3) Class I substances (listed at Appendix A to Subpart A) include certain CFCs, Halons, HBFCs, carbon tetrachloride, trichloroethane (methyl chloroform), and bromomethane (Methyl Bromide). Class II substances (listed at Appendix B to Subpart A) include HCFCs.

B. If the permittee performs a service on motor (fleet) vehicles when this service involves an ozone-depleting substance refrigerant (or regulated substitute substance) in the motor vehicle air conditioner (MVAC), the permittee is subject to all applicable requirements. Note: The term “motor vehicle” as used in Subpart B does not include a vehicle in which final assembly of the vehicle has not been completed. The term “MVAC” as used in Subpart B does not include the air-tight sealed refrigeration system used as refrigerated cargo, or the system used on passenger buses using HCFC-22 refrigerant. [40 CFR 82, Subpart B]

C. The permittee shall comply with the following standards for recycling and emissions reduction except as provided for MVACs in Subpart B: [40 CFR 82, Subpart F]

- (1) Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to § 82.156;
- (2) Equipment used during the maintenance, service, repair, or disposal of appliances must

- comply with the standards for recycling and recovery equipment pursuant to § 82.158;
- (3) Persons performing maintenance, service, repair, or disposal of appliances must be certified by an approved technician certification program pursuant to § 82.161;
 - (4) Persons disposing of small appliances, MVACs, and MVAC-like appliances must comply with record-keeping requirements pursuant to § 82.166;
 - (5) Persons owning commercial or industrial process refrigeration equipment must comply with leak repair requirements pursuant to § 82.158; and
 - (6) Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to § 82.166.

SECTION XXI. TITLE V APPROVAL LANGUAGE

A. DEQ wishes to reduce the time and work associated with permit review and, wherever it is not inconsistent with Federal requirements, to provide for incorporation of requirements established through construction permitting into the Source's Title V permit without causing redundant review. Requirements from construction permits may be incorporated into the Title V permit through the administrative amendment process set forth in OAC 252:100-8-7.2(a) only if the following procedures are followed:

- (1) The construction permit goes out for a 30-day public notice and comment using the procedures set forth in 40 C.F.R. § 70.7(h)(1). This public notice shall include notice to the public that this permit is subject to EPA review, EPA objection, and petition to EPA, as provided by 40 C.F.R. § 70.8; that the requirements of the construction permit will be incorporated into the Title V permit through the administrative amendment process; that the public will not receive another opportunity to provide comments when the requirements are incorporated into the Title V permit; and that EPA review, EPA objection, and petitions to EPA will not be available to the public when requirements from the construction permit are incorporated into the Title V permit.
- (2) A copy of the construction permit application is sent to EPA, as provided by 40 CFR § 70.8(a)(1).
- (3) A copy of the draft construction permit is sent to any affected State, as provided by 40 C.F.R. § 70.8(b).
- (4) A copy of the proposed construction permit is sent to EPA for a 45-day review period as provided by 40 C.F.R. § 70.8(a) and (c).
- (5) The DEQ complies with 40 C.F.R. § 70.8(c) upon the written receipt within the 45-day comment period of any EPA objection to the construction permit. The DEQ shall not issue the permit until EPA's objections are resolved to the satisfaction of EPA.
- (6) The DEQ complies with 40 C.F.R. § 70.8(d).
- (7) A copy of the final construction permit is sent to EPA as provided by 40 CFR § 70.8(a).
- (8) The DEQ shall not issue the proposed construction permit until any affected State and EPA have had an opportunity to review the proposed permit, as provided by these permit conditions.
- (9) Any requirements of the construction permit may be reopened for cause after incorporation into the Title V permit by the administrative amendment process, by

DEQ as provided in OAC 252:100-8-7.3(a), (b), and (c), and by EPA as provided in 40 C.F.R. § 70.7(f) and (g).

- (10) The DEQ shall not issue the administrative permit amendment if performance tests fail to demonstrate that the source is operating in substantial compliance with all permit requirements.

B. To the extent that these conditions are not followed, the Title V permit must go through the Title V review process.

SECTION XXII. CREDIBLE EVIDENCE

For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any provision of the Oklahoma implementation plan, nothing shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

[OAC 252:100-43-6]



PART 70 PERMIT

AIR QUALITY DIVISION
STATE OF OKLAHOMA
DEPARTMENT OF ENVIRONMENTAL QUALITY
707 N. ROBINSON STREET, SUITE 4100
P.O. BOX 1677
OKLAHOMA CITY, OKLAHOMA 73101-1677

Permit No. 98-171-C (M-2)

NORIT Americas USA, Inc,

having complied with the requirements of the law, is hereby authorized to construct the significant modifications at their activated carbon facility at 1432 6th Street, Mid-America Industrial Park, Pryor, Mayes County, Oklahoma,

subject to standard conditions dated July 21, 2009, and specific conditions, both attached.

This permit shall expire 18 months from the date below, except as authorized under Section VIII of the Standard Conditions.

Eddie Terrill, Director

Date

Date

Chris Soap, Plant Manager
NORIT Americas, Inc.
1432 6th Street, Mid-America Industrial Park
Pryor, OK 74361-4434

SUBJECT: Permit Number: 98-171-C (M-2)
Facility: Pryor Activated Carbon Plant
Location: Same

Dear Mr. Soap:

Air Quality Division has completed the initial review of your permit application referenced above. This application has been determined to be a **Tier II**. In accordance with 27A O.S. § 2-14-302 and OAC 252:004-7-13, the enclosed draft permit is now ready for public review. The requirements for public review include the following steps that you must accomplish:

1. Publish at least one legal notice (one day) in at least one newspaper of general circulation within the county where the facility is located. (Instructions enclosed)
2. Provide for public review (for a period of 30 days following the date of the newspaper announcement) a copy of this draft permit and a copy of the application at a convenient location **within the county** of the facility.
3. Send to AQD a copy of the proof of publication notice from Item #1 above together with any additional comments or requested changes that you may have on the draft permit. Please note that several issues concerning the most recent compliance evaluation of the facility remain to be resolved. If agreements are reached that reflect on terms of this permit, please include references to such agreement in your comments.

Thank you for your cooperation in this matter. If we may be of further service, please contact the permit writer at (918) 293-1600. Air Quality personnel are located in the DEQ Regional Office at Tulsa, 3105 E. Skelly Drive, Suite 200, Tulsa, OK, 74105.

Sincerely,

Herb Neumann
Air Quality Division

Chris Soap, Plant Manager
NORIT Americas, Inc.
1432 6th Street, Mid-America Industrial Park
Pryor, OK 74361-4434

SUBJECT: Permit Number: 98-171-C (M-2)
Facility: Pryor Activated Carbon Plant
Location: Same

Dear Mr. Soap:

Enclosed is the permit retroactively authorizing construction of the primary carbonizer and other equipment at the referenced facility. Please note that this permit is issued subject to certain standard and specific conditions, which are attached. These conditions must be carefully followed since they define the limits of the permit and will be confirmed by periodic inspections.

Also note that you are required to annually submit an emissions inventory for this facility. An emissions inventory must be completed on approved AQD forms and submitted (hardcopy or electronically) by April 1st of every year. Any questions concerning the form or submittal process should be referred to the Emissions Inventory Staff at 405-702-4100.

Thank you for your cooperation. If you have any questions, please refer to the permit number above and contact me at (918) 293-1600. Air Quality personnel are located in the Regional Office at Tulsa, 3105 E. Skelly Drive, Suite 200, Tulsa, OK, 74105.

Sincerely,

Herb Neumann
Air Quality Division

Department of Health and Environment
Bureau of Air and Radiation
Forbes Field, Building 283
Topeka, KS 66620-0001

SUBJECT: Permit Number: 98-171-C (M-2)
Facility: NORIT Americas, Inc. - Pryor Activated Carbon Plant
Location: SW/4 SE/4 Sec. 4, T20N, R19E, Mayes County, OK
Permit Writer: Herb Neumann

Dear Sir / Madame:

The subject facility has requested a retroactive analysis of a significant modification to a major stationary source for their activated carbon plant. Air Quality Division has completed the initial review of the application and prepared a draft permit for public review. Since this facility is within 50 miles of the Oklahoma - Kansas border, a copy of the proposed permit will be provided to you upon request. A copy of the draft permit is also posted on the Air Quality section of the DEQ web page: www.deq.state.ok.us

Thank you for your cooperation. If you have any questions, please refer to the permit number above and contact me at (405) 702-4100 or the permit writer at (918) 293-1624.

Sincerely,

Phillip Fielder, Engineering Manager
AIR QUALITY DIVISION

Missouri Dept. of Natural Resources
Division of Environmental Quality
P. O. Box 176
Jefferson City, MO 65102-0176

SUBJECT: Permit Number: 98-171-C (M-2)
Facility: NORIT Americas, Inc. - Pryor Activated Carbon Plant
Location: SW/4 SE/4 Sec. 4, T20N, R19E, Mayes County, OK
Permit Writer: Herb Neumann

Dear Sir / Madame:

The subject facility has requested a retroactive analysis of a significant modification to a major stationary source at their activated carbon plant. Air Quality Division has completed the initial review of the application and prepared a draft permit for public review. Air Quality Division has completed the initial review of the application and prepared a draft permit for public review. Since this facility is within 50 miles of the Oklahoma - Missouri border, a copy of the proposed permit will be provided to you upon request. A copy of the draft permit is also posted on the Air Quality section of the DEQ web page: www.deq.state.ok.us

Thank you for your cooperation. If you have any questions, please refer to the permit number above and contact me at (405) 702-4100 or the permit writer at (918) 293-1624.

Sincerely,

Phillip Fielder, Engineering Manager
AIR QUALITY DIVISION

Arkansas Dept. of Pollution Control and Ecology
5301 Northshore Drive
North Little Rock, AR 72118

SUBJECT: Permit Number: 98-171-C (M-2)
Facility: NORIT Americas, Inc. - Pryor Activated Carbon Plant
Location: SW/4 SE/4 Sec. 4, T20N, R19E, Mayes County, OK
Permit Writer: Herb Neumann

Dear Sir / Madame:

The subject facility has requested a retroactive analysis of a significant modification to a major stationary source at their activated carbon plant. Air Quality Division has completed the initial review of the application and prepared a draft permit for public review. Air Quality Division has completed the initial review of the application and prepared a draft permit for public review. Since this facility is within 50 miles of the Oklahoma - Arkansas border, a copy of the proposed permit will be provided to you upon request. A copy of the draft permit is also posted on the Air Quality section of the DEQ web page: www.deq.state.ok.us

Thank you for your cooperation. If you have any questions, please refer to the permit number above and contact me at (405) 702-4100 or the permit writer at (918) 293-1624.

Sincerely,

Phillip Fielder, Engineering Manager
AIR QUALITY DIVISION